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Topic 6

EU Involvement in Electricity and Natural Gas Transmission Grid Tarification

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Executive Summary

The current EU involvement in the regulation of TSO revenues and transmission grid tarification is limited and mainly addresses issues related to interconnection and supply security as well as the definition of underlying principles for third party grid access and capacity pricing. Heterogeneity among national, or even local, transmission tariffs might be an obstacle for functioning competition and adequate investments into the grids. Even though transmission tariffs account for only a small share of final industrial consumer electricity and natural gas prices, both their level and structure can have a strong impact on infrastructure investments and on how commodities are traded within and between countries.

We investigate whether the current challenges in the energy sector, accompanying the move towards "2014", "2020", and "2050", warrant a stronger harmonization in transmission tarification and, if yes, what form this should take and what the potential role of the EU could be in this process. To discover the need for further EU involvement and harmonization, we ask (1) whether the existing heterogeneities in regulatory practice might hamper adequate investments or impede efficient competition and, if yes, (2) whether new EU legislation in place and new EU instruments notably from the Third Package – *once enforced* – provide an efficient solution. Increased trans-national involvement may have benefits, such as the better functioning of markets and the facilitation of infrastructure development, but it also comes at a cost, such as increased information asymmetry between individual decision makers and higher-level coordinating or regulating institutions. Both have to be weighted carefully. Practical and political implementability of the proposed solutions (both in the near- and long-term) is one of our key concerns.

Chapter 2 provides the analytical framework to examine policy measures going beyond the national level. Three questions are to be answered: First, whether EU involvement is justified on the grounds of subsidiarity, considering that the higher European level of decision-making shall avoid pre-empting any area of legitimate Member State involvement. Second, whether the achievement of policy targets is hindered by profound and permanent market failures. And finally, whether the necessary regulatory actions could be decentralized among various local players and objectives be achieved based on voluntary regional cooperation instead of being the result of a top-down, centralized decision as to get a workable implementation process.

Chapter 3 addresses the regulation of TSO revenues. The observed heterogeneity in general price control mechanisms and instruments used to promote new investments probably does not hamper adequate investments in national infrastructures without a strong cross-border impact. Key parameters determining investment incentives such as an adequate risk-reward ratio, regulatory stability and transparency, are all issues national regulators can properly address. Cross-country comparability, however, has shown to be problematic which could make it difficult to attract funds from external investors needed to meet the substantial financing needs in the coming decades. Moreover, differing methodologies used to calculate the allowed revenue could actually hamper adequate investments regarding projects that have a regional (i.e. cross-border) impact.

We recommend for future EU involvement:

First, we do see neither the need nor the justification for an EU-wide harmonization of the regulation of TSO revenues. Nevertheless, we recommend that decisions regarding the projects with a pan-European impact might be taken on the EU level instead of being the result of a reaction to rates-of-return settled by national regulators in different Member States. Where a region-specific solution has to be found (e.g. offshore grid), decentral cooperation and coordination among relevant stakeholders are appropriate. Second, ACER should take the responsibility for benchmarking national practices and formulate an opinion about the appropriateness of various methodologies employed. Transparency (i.e. reporting) standards should be extended. Third, innovative solutions to trigger investments (e.g. competitive tendering or a European tariff component) should also become common tools.

In **Chapter 4** we analyze transmission grid tarification in the electricity sector. The heterogeneity does hamper both adequate investments and efficient competition. While the EU has defined general principles of tarification, EU involvement with respect to tariff design is very limited. The existing ITC mechanism is an ex-post instrument that intends to compensate TSOs for the costs resulting from hosting cross-border flows. Apart from some methodological weaknesses, it is not designed to incentivize the timely realization of grid investments or to allocate costs of new infrastructures. These issues are expected to be addressed by the proposed Energy Infrastructure Package. However, we identified some factors that might hamper the successful implementation and effectiveness of this new Regulation.

We recommend for future EU involvement:

First, to increase transparency, the cost components included in transmission tariffs should be harmonized. They should only include cost related to transmission network infrastructure. Second, it should be ensured that the behavior of grid users in the competitive sector is not distorted due to tarification, i.e. transmission tariffs covering the long-term cost of infrastructure should not be charged based on energy transported (i.e. in €/MWh). Instead they should be paid based on booked capacity or lump-sum, with charges being computed separately for different types of grid users in different areas so that charges properly reflect the network-related relevant characteristics of the network users. Third, tariffs should be allocated as far as possible based on the principle of cost causality. Locational signals should be introduced, taking into account national system specificities based on sound methodologies and providing reliable ex-ante signals. The provision of time signals to improve efficient short-term use of the existing grid should be considered, too. To give economic signals to generators, obviously a certain share of the tariff needs to be paid by them. In order to avoid a distortion of competition, the EU might fix an average share of the G/L component; thus, introduce a minimum G-component.

Fourth, the EU should call for the removal of the legal barriers that might impede grid investments where strong geographical asymmetries in costs (i.e. investment needs) and benefits occur. It is necessary that third parties can invest where incumbent TSOs do not show interest to realize identified priority projects. Given the uneven distribution of benefits among stakeholders arising from increased interconnection capacities and the concern that national regulators tend to protect domestic consumers from rising prices, effective means have to be found to incentivize NRAs to support the development of identified priority projects.

In **Chapter 5** we discuss transmission grid tarification in the natural gas sector. Heterogeneity in tariff structures itself does not hamper adequate investments while it might certainly hamper efficient competition. There are more than 30 entry-exit zones with mainly administratively determined borders. Furthermore, a systematic bias exists in the form of a cross-subsidization between short-distance transmission and long-distance transportation and domestic consumers tend to cross-subsidize transit flows. Other obstacles to functioning competition include contractual congestion, inefficient pricing of non-standard products, a persisting lack of backhaul capacities, or the limited compatibility of capacity products offered. The implementation of new legislation (i.e. Third Package, Network Code on capacity allocation mechanisms) substantially will increase transparency and compatibility, reduce therefore transaction costs and will facilitate natural gas trade and competition. However, it does not address all persisting obstacles.

We recommend for future EU involvement:

First, the EU should set principles for determining the ideal size of entry-exit zones, but let involved NRAs and TSOs agree on the result. Boundaries of price zones should reflect the technical and economic conditions rather than political borders; mergers of market areas shall be evaluated on a case-by-case basis based on expected economic benefits and costs. Once market areas are merged, there are good economic reasons to implement a system of common tarification. The role for the EU here should be limited to support agreements between the respective stakeholders; the actual implementation of harmonization of tariff structures and definition of a mechanism to compensate TSOs can be managed at regional level.

Second, we recommend some harmonization in tarification to ensure that the breakdown of costs among grid users and among entry- and exit points is designed to respect as much as possible the principle of cost-reflectiveness. Adequate discounts on short-haul transports should be encouraged. Asymmetric reallocation of costs such that 'captive' domestic consumers intentionally have to bear disproportionately high costs, shall be prohibited. Third, the EU, through ACER, should formulate a set of 'good practice guidelines' regarding natural gas transmission tarification. Entry- and exit charges should be actively used to provide locational signals to grid users wherever this is economically reasonable. Furthermore, commodity-related components should reflect short-run marginal costs to avoid distortions in the behavior of shippers in the commodity market and network tariffs should clearly be identified, containing only those cost elements that are related to the transmission.

Finally, **Chapter 6** concludes.

1. Introduction

Background

Transmission tariffs account for only about 12% (7%) of final industrial consumer electricity (natural gas) prices, but both their level and structure can have a strong impact on infrastructure investments and on how commodities are traded within and between countries. Heterogeneity among national, or even local, transmission tariffs might be an obstacle for functioning competition and adequate investments into the grids.

The European electricity and gas industries are currently both on the path to reach energy and environmental objectives. The key EU energy policy goals when looking at transmission grid tariffs are threefold: to link regional markets and eliminate any barriers to efficient cross-border trade ("2014 target"); to support the reduction in greenhouse gas emissions, promote renewable energy sources, increase energy efficiency – thus, to support the move towards full decarbonization ("2020 and 2050 targets"); and at the same time, to ensure supply security, both in the long- and in the short-term.

The realization of these goals will require substantial changes in the resource mix and network infrastructures and involves a number of well-known challenges related to energy infrastructures, both for natural gas and electricity. In this context, transmission tariffs have different objectives to fulfill that are not always compatible with each other, such as the recovery of short-run and long-run costs, and the indication of short-run and long-run capacity shortages. Historically, the regulation of grid operators was a domain of national Ministries or regulatory authorities; with the implementation of the third European energy package, issues about the EU involvement have come to the fore that may imply a changing role of the EU, both in the shorter-term, until 2014, and in the longer-term.

The current EU involvement in the regulation of TSO revenues and transmission grid tarification is limited and mainly addresses issues related to interconnection and supply security as well as the definition of underlying principles for third party grid access and capacity pricing. However, sophisticated cost-benefit allocation mechanisms might be required to align costs of infrastructure investments benefiting several Member States. As EU grids are said to enter a period of massive investments (hundreds of billion €; see e.g. EC, 2011), an efficient cost-benefit alignment of grid investments and operation across Member States will influence decisions taken by TSOs and national regulators. This necessarily makes the role of the EU in electricity and gas grid tarification a very timely issue.

This 6th report of THINK addresses the question of alternative forms of trans-national involvement in electricity and gas transmission tarification. We ask whether the current challenges in the energy sector warrant a stronger involvement in transmission tarification and, if yes, what form this involvement could take and what the potential role of the EU might be in this process. Our hypothesis is that increased trans-national involvement may have benefits, such as the better functioning of markets and the facilitation of infrastructure development, but that this comes at a cost, such as increased information asymmetry between individual decision makers (e.g. TSOs) and higher-level coordinating or regulating institutions. Both have to be weighted carefully. Depending on what policy goals are considered more important, different instruments can be judged differently, so that no 'first-best' institutional setting for transmission tarification can be identified.

Scope of our report

Figure 1 displays different stages of an infrastructure development, from the planning to the final cost allocation. At each stage, regulation plays a role. Our analyses will focus on two key areas of regulation regarding the transmission network. The first includes the regulation of TSO revenues, stipulating the incentives for TSOs' investment decisions; the second is the pricing of network services, or tarification in the narrow sense, i.e. the allocation of costs to grid users. "Tarification" means all cost allocation mechanisms, namely those used to allocate the amount of TSO revenues among grid users and those used to allocate network costs among the various TSO zones. The proper planning and financing of infrastructure are not the core focus of this report; however, since they are inter-linked with revenue regulation and grid tarification we will take them into account where needed.

We will address both national and cross-border infrastructures and give recommendations for a short- and medium-term perspective (2014, 2020). We will notably see if a more active role of the EU is more relevant for the infrastructure involving more than one Member State.

Figure 1: Comprehensive overview of the areas of regulatory intervention

Area of regulatory intervention	Infrastructure planning	Infrastructure financing	Regulation of TSO revenues	Cost allocation	
				... among grid users	... among zones
Involved stakeholders	TSOs + ENTSOs/ACER + regional investm. groups	MS, EU, wide variety	NRA → system operator	TSO → grid users	EU → MS → system operator
	↓	↓	↓	↓	↓
	Which projects?	Assure financial viability	Defining the allowed revenues	Recovery of regulated costs	Compensation among stakeholders

Source: THINK own depiction

Methodology

Existing studies investigating natural gas and electricity grids mainly focus on isolated issues such as principles for tarification (e.g. Lévêque, 2003b; Pérez-Arriaga and Smeers, 2003), measures to promote interconnector projects (e.g. Kapff and Pelkmans, 2010; Riechmann, 2011; Supponen, 2011), financing (e.g. Hirschhausen, 2011), modeling of optimal grid investments based on social welfare optimization (e.g. Rosellón and Weigt, 2011), or descriptive studies on existing regulatory practices (e.g. Green, 1997; Montero et al. 2001; Sakhrani and Parsons, 2010). Our report distinguishes from these works both in terms of scope and methodology. Taking current heterogeneity among national regulatory practices as a starting point, we investigate the need for EU involvement and harmonization given that grids are key to achieve EU energy policy goals. To address new challenges, regulation of revenue and transmission tarification should: (1) ensure adequate investments into the grid and (2) avoid any distortion in competition impeding an efficient operation of the energy system.

1 - **Ensure adequate investments into the grid**. Adequate investments address quantity-, timing- as well as quality issues. A sound regulatory design should provide sufficient incentives to promote the necessary investment, but at same time, should achieve overall system adequacy (tuning both load and supply) at minimum cost. It should also inhibit the monopoly rent-seeking behavior that would result in under-investment. Nevertheless, one has to be aware of the potential trade-off between seeking the optimum solution which might delay the investment and making timely investment at the risk of under- or over-investment. Moreover, as we are in a dynamic period with technical innovations along the whole value chain and considerable changes happening in system architecture, the regulation of grid operators' investments should enable upstream and downstream innovations (like e.g. new characteristics of offshore wind generation; see also THINK, 2012) and allow for the necessary R&D.

2 - **Avoid any distortions in competition impeding an efficient operation of the energy system**. First, regulation and tarification of the transmission grid should not distort the behavior of generators and suppliers in the energy market (from long-term to real-time). Second, the existing differences in national tariffs should not hamper efficient competition across Member State borders. It is of particular importance to the EU as a whole as to its numerous constituencies that all economic opportunity of reducing costs, uncertainties and risks of our energy systems are duly exploited.

We use these two criteria to carry out the evaluations. To discover the need for further trans-national (or EU-) involvement and harmonization, we will investigate whether the current heterogeneity of tariff design and regulation is problematic by finding answers to three questions:

1. Does the heterogeneity in national regulatory practices hamper adequate investments?

2. Does the heterogeneity in national regulatory practices distort efficient competition?

3. Are new EU legislations in place and new EU instruments notably from the Third Package – *once enforced* – suitable to support adequate investments and efficient competition?

We will assume that European energy markets are as they currently are – far from the ideal picture of perfect market economics and will deliberately welcome what economists call 'second best' or 'third best' outcomes. We also explicitly recognize both in our analysis and in our policy advice that economic arrangements stand on given institutions. The practical and political implementability of the proposed solutions (both in the near- and long-term) is therefore one of our key concerns.

Our report is structured as follows. Chapter 2 introduces economic rationales for EU involvement and harmonization as well as different forms thereof. Chapter 3 discusses EU involvement regarding the regulation of TSO revenues. Chapters 4 and 5 address EU involvement regarding transmission tariff structures in the electricity and natural gas sectors, respectively. Chapter 6 concludes and summarizes recommendations.

2. Trans-regional coordination and the potential role of the EU: The case of transmission infrastructures

In the following, we provide the analytical framework for the analysis of policy measures going beyond the national level. Three questions are to be answered: First, whether EU involvement is justified on the grounds of subsidiarity considering that the higher European level of decision-making shall avoid preempting any area of legitimate Member State involvement. Second, whether the market areas targeted by the policy objectives are impeded to effectively deliver due to consistent and permanent market failures. And finally, whether the necessary regulatory actions could be decentralized among various local players and objectives be achieved based on voluntary, regional cooperation instead of being centralized ("Brussels or Ljubljana") as to get a workable implementation process.

2.1 Economic rationale for EU involvement and harmonization

Alternative forms of EU involvement have been addressed previously by the THINK Report No. 4 (THINK, 2011). They are based on the implicit understanding that the move of regulatory power from a lower to a higher federal level, i.e. from the national to the trans-national or even the European level, has benefits and costs: benefits may result in the convergence of national policies and, thus, to overall economic benefits that can be shared; transnational externalities can be internalized and thus treated more efficiently, and network benefits be reaped that might not have been realized by national policies. Potential disadvantages of a more intense trans-national or even EU-involvement (and thus arguments favoring national approaches) are the disregard of national specifics, reduction of institutional competition between alternative policy approaches, and the loss of decentralized "participatory energy".

There is a need for higher level action once the lower level cannot reap the benefits of integration, or when essential functions such as financing, are more efficiently solved at the higher level. The new institutional economic approach suggests to consider the transaction costs of alternative regulatory regimes: these include the costs of running markets and organizational hierarchies (such as national governments, trans-national and European institutions), but also costs resulting from information asymmetries between principals and agents, financing costs, etc. Also questions of political commitment, reliability, and time consistency of decisions affect the choice of an appropriate federal level. For example, if one (small) country can put an important transmission line at the other end of Europe in peril, this might speak in favor of high centralization of decision power. Ultimately, the appropriate institutional setting should be chosen such that the sum of production costs and transaction costs is minimized.

2.1.1 Is any trans-national involvement justified on the grounds of subsidiarity?

In theory, if the whole European electricity (or natural gas) sector would be controlled by a single TSO underlying European (instead of national) regulation, it would permit of complete harmonization of the regulation of transmission activities and transmission pricing regimes. Political or property borders would not play any role. Trading across national boundaries would be "seamless". Of course, the EU looks different with (sub-) national TSOs and a "*patchwork of different policy regimes*" (ECF, 2011, p. 4). In such a setting with multiple stakeholders – being not only numerous TSOs but also various grid users, NRAs, governments, etc. – many challenges appear. A lack of harmonization might hamper a level playing field and distort efficient competition. Strong asymmetry in costs and benefits of existing or new infrastructures actually calls for due cross-country compensation mechanisms; etc.

However, any EU involvement must not go beyond what is necessary to achieve the high-level objectives in the EU Treaties, except for areas of EU exclusive competences. EU action shall only be taken when it is more effective than actions at national, regional, or local level. Thus, regulatory powers should be assigned to national or European levels of authority following the principle of subsidiarity – as defined in Art. 5 of the Treaty of the European Union[1].

From an institutional perspective, there are shared competences between Member States and the EU regarding the achievement of the European energy policy goals – i.e. the completion of the internal market, a sustainable and environmentally friendly energy system, and security of energy supplies (Art. 194, Treaty of the Functioning of the EU). It is then legitimate to look at this more closely to see if there are substantial economic benefits to be made from a renewed EU involvement.

2.1.2 Is there any economic rationale for public involvement beyond the Member State level?

The following paragraphs list several possible economic rationales justifying involvement in the regulation and tarification of transmission infrastructures that goes beyond the level of the Member States; this could be decentral regional cooperation or intervention at the European level.

1 See also Konstadinides (2009). See Kapff and Pelkmans (2010) and further literature therein [Pelkmans, 2006(b)] for an in-depth discussion of the development and application of a functional subsidiarity test to EU (energy) policy.

1// Presence of externalities

Individual actions in many cases have direct implications on other stakeholders (other Member States, TSOs, grid users, etc.; see e.g. Crampes, 2011; Riechmann, 2011) while being not properly handled by ordinary market mechanisms. These “externalities” can be positive, (e.g. new transmission lines enhance short- and long-term supply security or reduce congestions, which basically are public goods; they furthermore are a key enabler of the move towards “2020”). Benefits, being not yet recognized and/or monetized for a large number of stakeholders, may be substantial. Thus, positive externalities could lead to a situation where benefits that can be captured by the investors are smaller than the overall societal benefits. The externalities also can be negative, (e.g. costs incurred in transit countries that do not directly benefit). Another type of interaction actually works properly in the market as the case of an increased market inter-connection which leads to price alignment with areas of lower prices facing price increases. While being “market normal” these price movements cause large transfers of welfare across borders and among stakeholders and should be carefully looked at (see below 2// “distributional concerns”).

In the absence of functioning mechanisms to correct for these externalities, decentralized decision-making will not result in the socially optimal investments from a regional or an EU-wide perspective. Since externalities typically call for multi-lateral agreements, they could be one fundamental reason for additional EU involvement and justify a more centralized decision making and extended common actions.

2// Distributional concerns

A second rationale for trans-national involvement are distributional concerns [to some extent related to 1//]. As soon as multiple stakeholders are involved, diverging interests can hamper efficient decision making. This could even become more severe for two reasons: (a) It is not trivial to identify and quantify benefits; particularly for new grid investments since beside the monetary benefits they are also contributing to supply security and enable the move to a low-carbon economy; (b) there could be an asymmetry in costs vis-à-vis benefits related to the operation of existing infrastructures or new lines. It is true especially in well-interconnected electricity systems and consequently will become more and more relevant the more we approach towards the "2014" ideal of a functioning internal market. Mechanisms ensuring a fair distribution of costs among beneficiaries have to be developed ex-ante (before the investment) and not only ex-post (on already existing infrastructures).

3// Discovery of 'best practice'

A third rationale for trans-national involvement is to stimulate the information benefits we can get from various national regulatory authorities being learning from their diverse regulatory approaches. Many of these regulatory differences originate from due factors, including individual market characteristics, the process of development of the national regulation, the resulting economic and institutional endowment of the regulatory authorities (see also Rious et al., 2011), etc. Therefore, for many issues there will not be one unique second- (or third-) best solution that shall be easily implemented everywhere in the European Union. One should rather get "ad hoc" adequate measures that once implemented somewhere could help to achieve certain policy goals in a particular context. An active and coherent cross-national exchange of regulatory experiences – coordinated and evaluated centrally through a European institution such as ACER – can therefore reveal the working of regulation in real-world settings, increase market transparency, spread innovating regulatory models, and in some cases establish a kind of recognized 'best practice' (as we have seen with "market coupling" in the electricity sector or "open season" in the gas sector).

2.1.3 Decentral coordination and EU instruments

Coordination and cooperation among stakeholders from different countries become especially relevant when cross-border infrastructures are involved (see also Bujis et al., 2010; Glachant and Khalfallah, 2011). These will play a more and more important role with the interconnection of formerly more or less isolated markets. In the coming "2014" internal energy market multiple TSOs will be responsible for planning, investing and operating the grid and decisions regarding permit granting and regulation of infrastructures or issues related to tarification will have to be taken by more than one national regulator. The question that immediately appears is whether any voluntary cooperation to solve the targeted problems is feasible and credible.

On the one hand, several initiatives of cooperation and common action have been initiated in the past, being a very typical feature of the EU energy reform processes: e.g. the electricity and natural gas Regional Initiatives, ENTSO-E's predecessor ETSO, Gas Infrastructure Europe, the Florence and Madrid Forums in which NRAs, governments, the Commission, TSOs, traders and grid users work together to move towards the internal market, or numerous bilateral and multilateral agreements. In electricity, countries like France or Germany have developed transmission lines to Switzerland to secure regional optimization, a development that might be emulated to connect the "blue battery" in Scandinavia to continental Europe and the UK. A more regional scenario might even be a plausible institutional form for superhighway projects such as the North Sea Grid, where the North Sea Offshore Grid Initiative (NSOGI) is currently proceeding without a European coverage. Such more decentralized solutions based on regional cooperation benefit from lower transaction costs and a possible increase of local participation and involvement.

On the other hand, voluntary cooperation might fail when long-term commitment of involved parties cannot be ensured; "NRAs are (by nature) nationally focused" (CIEP, 2009, p. 39). This becomes more severe when stronger externalities and/or more money are involved; or when it is more difficult to identify benefits and allocate costs. Obviously, within voluntary agreements the room for sanctions in case of non-compliance is rather limited as badly exemplified by the major European electricity blackout in 2006. An example where voluntary action clearly failed is the enabling of reverse flows in natural gas pipelines. Even though these investments are of quite low cost and can significantly increase supply security, their importance was only truly recognized, and required for within a new EU Regulation, after the gas crises caused by conflicts between Russia and transit countries during the past years.[2] Another example from the electricity sector can appear for the North and Baltic Sea Grid expansions. Egerer et al. (2011) indicate that countries with a traditional trade surplus and modest generation suffer a loss in the overall welfare (such as France and Germany), while other countries stand to benefit (e.g. UK, Netherlands, Norway, or Sweden). Buijs et al. (2011) also conclude that a negative welfare effect can occur in an optimal supranational plan for the transmission investment planning. In this case, the net loser is unlikely to be cooperative to undertake the investment project, unless a sound cost-benefit allocation mechanism is in place.

2 Regulation 994/2010 still leaves the decision on possible exemptions from reverse flow investments on interconnectors to NRAs. The past has shown that exemptions are granted in order to protect own markets from competition. Thus, it is of utmost importance, to enforce this existing piece of EU legislation.

2.2 Choosing among different forms of EU involvement

The different forms of EU involvement must be considered in the light of the trade-offs sketched out above, mainly the reasons for trans-national action, and then the specific arguments for more decentral or more central policy intervention.

Within this report, we do not consider "EU involvement" as referring to a single type of tool. EU involvement is only a way to get more European welfare and policy achievement. It has to be tailored in practice to really cure the deficiencies we are facing and, thus, might target amongst others harmonization among national practices, the enforcement of existing pieces of legislation, supporting innovation, standardization, etc. We distinguish three different forms of EU involvement[3], with the term "EU" referring to a host of European political institutions including the European Commission, Parliament and Council, and attached institutions like the Association of the Council of Energy Regulators (ACER) or the European Investment Bank (EIB):

First form – ***EU definition of general underlying principles***: With this type of involvement the EU does not accomplish by itself. It only frames the process of actions being still decentralized among Member States and local players. It provides the basis for a common understanding and ensures that decentralized regulatory actions may converge towards the high-level energy policy goals ("2014" and/or "2020"). An example are the principles for electricity and natural gas trans-

3 See also Knill and Lenschow (2005) for an interesting continuative analysis of the relationship between supra-national regulatory policy and national responses. They distinguish between 'governance by compliance' as the strongest form of EU legislation with leaves little or no discretion to national implementers, 'governance by competition' which is basically restricted to a definition of legally binding underlying principles, and 'governance by communication' (i.e. the stimulation of information exchange and best practice).

mission pricing specified in Regulations 714/2009 (Art. 14) and 715/2009 (Art. 13), respectively: prices shall be transparent, cost reflective, non-discriminatory, and take into account network security – all being necessary preconditions to allow the development of a functioning internal market.

Second form – ***EU harmonization of the set of regulatory instruments***: This form of involvement prescribes concrete rules to be adhered to but leaves the implementation up to the Member States, in some cases in coordination with a European institution. A harmonization of the existing alternative instruments becomes relevant if too much divergence in national regulatory designs impedes the achievement of higher (i.e. regional- or EU-) level policy goals. An example would be the by ERGEG proposed framework guidelines regarding capacity allocation mechanisms in the natural gas sector (ERGEG, 2010d). It notably recommends harmonization of capacity products being offered as well as capacity allocation procedures.

Third form – design and implementation of a ***single EU instrument*** regardless of local specificities: An EU instrument is a very strong form of EU involvement. It is appropriate when (a) harmonization should restrict the variety of regulatory instruments and the Member States agree on a single most suited instrument (as with the EU ETS, the Ten Year Network Development Plans or the gas security of supply regulation R994/2010) and/or when (b) individual action cannot solve a specific problem and only a single coordinated instrument can provide a common action. An example is the inter-TSO compensation mechanism for electricity. Clearly an EU-wide instrument is only justified if lower levels of intervention, such as decentral, regional solutions, are unlikely to solve the problems.

3. Regulation of TSO revenues

3.1 Introduction

This chapter addresses the regulation of TSO revenues. Regulatory intervention regarding electricity and natural gas transmission is necessary to ensure non-discriminatory access to the grid and avoid monopoly pricing for infrastructure use[4]. Regulators aim at increasing overall efficiency and sharing any resulting gains with consumers. The main constraint thereby is to find the optimal balance between giving enough long-run economic incentive for reliable grid operation and necessary grid expansions on the one hand, and inhibiting the extraction of monopoly profits by the TSO on the other. We investigate current regulatory practices in Member States from the following two aspects[5]:

1 - **Ensure adequate investments**: Transmission network assets shall provide the service of electricity or natural gas transmission in a given area, taking into account the existing configuration of upstream supply and downstream consumption, ensuring defined levels of quality of service and supply security, and supporting the move towards "2014", "2020" and in

4 It should be noted that unlike electricity or natural gas distribution or electricity transmission, the natural gas long-distance transportation infrastructure is not necessarily a natural monopoly in all cases (see also Jamasb et al., 2008, and references therein). Although there are clearly economies of scale related to the pipeline diameter, some markets for natural gas can be served by several transmission pipelines.

5 Baker and Gottstein (2011), referring to the electricity sector, also highlight another important aspect. Given the large magnitude of investments required to meet 2014-, 2020-, and 2050 targets, it is not only important to ensure that realized investments are fully justified and represent the most cost-effective alternatives, but also that network operation is improved such that existing assets – which often have quite low average utilization rates – are optimally used. Actually, the same is true for natural gas, where especially the problems of contractual congestion and an unsatisfactory use of storage capacities (according to ERGEG (2011c) most storage facilities are congested and competition between storage operators is limited) cause sub-optimal infrastructure usage.

the longer-term also "2050"[6].

Adequate investments refer to (i) the right 'amount' of investments, i.e. neither under- nor over-investment into grid infrastructures, (ii) the right 'types' of investments (architecture, cost, technology, energy policy adequacy – see Chapter 1) as well as (iii) the right timing.

- Without regulatory intervention, the revenue maximization behavior of a monopolist (or oligopolist) would lead to investments below the social optimum that would occur in a perfectly competitive market. On the other hand, a too high allowed rate-of-return (RoR) will result in over-investment and thus unjustified high network costs that will be passed through into grid user tariffs. The right balance needs to be found.
- Beside the RoR, other factors have an at least equally important impact on stakeholders' incentives to invest in grid infrastructures, such as regulatory stability, access to financial means (internal and external equity, debt), transaction costs (e.g. due to time-consuming permitting procedures), etc.
- Regulation furthermore can be designed such that it supports the achievement of other policy goals (e.g. investments into R&D[7]). Adequate investments may also include projects that are socially desirable but not profitable from the isolated investor's point of view (e.g. facilities ensuring security of supplies without their capacity being booked over the long-term). In these cases, the regulator can set extra incentives.
- The timeliness of investments is of utmost importance, too. It takes several years before a planned infrastructure finally is constructed and starts operation. Delays due to inefficiencies in the permit granting process hamper adequate investments. Also the presence of uncertainties will motivate potential investors to post-pone projects to benefit from further information and thus less uncertainty at a later moment in time.

2 - **Avoid any distortions in competition**: If the regulation of TSO revenues is badly designed with the allowed revenue being too high, this will mirror in unreasonably high tariffs for grid users and restrict their production and consumption activities accordingly. An unjustified RoR in one country could not only distort the short-term behavior of electricity generators or natural gas suppliers, but also competition among players from different Member States.

3.2 Current regulatory practice

To date, the regulation of electricity and natural gas grids is under national responsibility. The decentralized decision making and development of national regulatory regimes (dependent on individual sector characteristics, historical evolution of the regulatory design, national policy priorities, regulatory capabilities, etc.) have resulted in a wide heterogeneity

6 Directives 2009/72/EC (Art. 12) and 2009/73/EC (Art. 13) provide the legal formulations of the tasks of electricity (and respectively natural gas) TSOs. See also Rious et al. (2008) for an interesting discussion on diversity of TSO design given that they all have to fulfill the same three basic tasks, namely (i) short-term management of electricity flow externalities, (ii) longer-term grid development, and (iii) coordination with neighboring TSOs to deal with cross-border effects.

7 It should be noted that technical innovation is less important in the natural gas market. For the electricity sector, major needs for technological or process developments are at the distribution level, given the move towards a system that will have to absorb substantial distributed generation and where also demand side management gains in importance. In this context, THINK (2011) concludes, amongst others, that "smart grids need smart regulation" and that the conventional regulatory framework has several shortcomings. It does not incentivize grid companies to innovate, and if they do innovate, they are confronted with grid users that have disincentives to participate in the ongoing innovation. Therefore, the authors recommend a harmonization of the regulation of transmission and distribution grids in the form of coherence requirements and that regulators could be mandated to enable the transition towards a sustainable energy system.

in current regulatory practices. In the following, we describe key parameters regarding the current regulation of electricity and natural gas TSOs' revenues and highlight differences among national practices; for more details see e.g. Kema/Rekk (2009), Laprise (2009), Hadush (2009), as well as national regulators' websites and documentation. We analyze heterogeneity regarding two aspects: (a) general price control mechanisms and their implementation as well as (b) instruments used to promote investments.

3.2.1 General price control mechanisms and their implementation

First, we observe that *various forms of general price control mechanisms co-exist*, including cost-plus, rate-of-return, price-cap and revenue-cap regulation. ERGEG (2007) provides some principles for the regulation of TSO revenues, i.e. the recovery of costs of transmission investments. These include amongst others that a reasonable return on capital shall be provided, depreciation should be oriented on the expected economic lifetime of assets, and the as basis for the risk-free interest rate conventional long-term government bonds (5-10 years) are recommended. However, these still leave much room for diversity.

Real-world regulation typically deviates from the simple standard textbook cases and a number of modules are combined to address different policy objectives. For example, the UK RIIO model will be based on an ex-ante price control combined with investment incentives, an innovation stimulus package, a strong output orientation and also a longer regulatory period (see Box 2 for more details). Italy uses a rate-of-return approach for the allowed return on assets, a price cap for OPEX and depreciation and a separate price cap for the commodity charge.

Second, there is wide *heterogeneity regarding the calculation of the allowed revenue*. The calculation of the Regulated Asset Base (RAB) differs in both (i) components included [e.g. fixed assets are always included; working capital might be included at varying levels; 'assets under construction' might be included or not] and (ii) and their evaluation [using historic costs, replacement value, indexed historic costs or standard cost; treatment of fully amortized assets, treatment of assets partly financed by third parties or public subsidies]. There is cross-country variation regarding the numerous parameters applied, such as risk-free interest rates, debt- and market premiums, the assumed capital gearing share, beta factors, etc. and thus also variation in the calculation of CAPEX, OPEX, or the WACC. Taxes might be included or not; the calculation of the allowed rate-of-return might be based on nominal or real values.

Third, the *regulatory period*, as one of the major factors signaling regulatory stability, varies considerably among Member States (e.g. one year in Slovenia in the past, four to five years in many Member States (e.g. Belgium, Germany, Italy), eight years for the RIIO model). It should be noted that regulatory stability is crucial to incentivize capital-intensive long-term investments, typically undertaken by risk-averse market actors. "Investors want a durable pathway rather than a perfect or uniform one" (ECF, 2011, p. 18); stakeholders concordantly agree that regulatory stability is one major pre-condition for adequate investments (see e.g. ERGEG, 2007; ENTSO-E, 2011c). Changes in regulation can have substantial effects on the profitability of a project; ex-ante uncertainty about possible future adaptations will be incorporated in private investors' decision making[8]. Long-term

8 The significant deviation between economic lifetime of TSOs' assets (about 40 years) and the duration of regulatory periods (about 1/10) indeed creates substantial uncertainty for grid operators. Unexpected changes in regulatory practice do not only have a direct impact on the profitability of existing and planned investments, but also have severe consequences on the trust private investors will give to future regulatory decisions, which is highly consequential since the political risk is one of the few that cannot be controlled by investors. E.g. the decision by the Spanish

commitments to future remuneration are required to attract investors and allow them to secure the necessary financing; thus, extending regulatory periods above the currently common three to five years as has been proposed in the UK, can help to improve investors' expectance of reasonable remuneration.

Though, "adequate investments" – as discussed above – do not only refer to the level of investments but also to their scope, or quality. One worrying fact is that current regulations mainly incentivize cost reductions; little attention is paid to innovation and cost minimization over the long-term (see e.g. ENTSO-E, 2011b). Pioneers actively taking into account the growing importance of RD&D are few: In the proposed UK RIIO model, technical and commercial innovation is encouraged through an innovation stimulus package giving support and rewards, incentives within the price control system and the option to give the responsibility for delivery to third parties. This issue is especially relevant for *distribution* grids; in transmission – the focus of our report – *technical* innovation is of less importance since these investments are few in number and one can expect that these will be assessed and realized on a case-by-case basis including innovation aspects explicitly. However, innovation also might target the development and implementation of new operational processes, adapted business structures, or novel commercial arrangements.

In summary, the heterogeneity in general price control mechanisms and their implementation results in varying incentives to invest in grid infrastructures, to enhance operating efficiency, to invest in RD&D and to be able to support the achievement of EU energy policy targets. It also makes cross-country comparisons extremely difficult, at a time where 'multinational' TSOs (TenneT, Elia) need to choose the region to invest and new financial sources need to be attracted.

Box 1: The UK "RIIO" model

The UK was the first country to introduce an RPI-X regulation with a strong focus on the maximization of economic (both productive and allocative) efficiency. The model actually was successful in reducing operational cost and has been adapted continuously during the last 15 years (see also Bartle et al., 2003).

To respond to the investment needs in the short-term and to the challenges originating from the ambitious climate and energy policy targets, Ofgem decided to alter its regulatory scheme again. Activities of the regulated companies should focus on (i) outputs to improve services to grid users, (ii) innovation targeting new services and long-run cost reductions, and (iii) incentives for productive efficiency. The proposed RIIO model, to be implemented in 2013, resembles more a further evolution rather than a complete revolution in the regulation of grid operators (Frontier, 2010; Glachant et al., 2011) and several open questions remain (see e.g. Pollitt, 2010).

"RIIO" stands for "setting Revenue using Incentives to deliver Innovation and Outputs" (Ofgem, 2010). This model of regulating electricity and natural gas transmission owners and DSOs incorporates three basic elements: (1) an ex-ante price control that sets the outputs that network companies are required to deliver and the revenue they are able to earn for delivering these outputs efficiently, (2) the option to leave the realization of infrastructure projects to third parties, and (3) a

government to cut solar subsidies retro-actively, or the decision by the German authorities regarding nuclear phase-out, will have long-lasting implications (see also ECF, 2011).

time-limited innovation stimulus. At the beginning of each price control period, Ofgem will establish outputs to be delivered and the companies will have to present a detailed business plan on how to deliver them. The regulatory period was extended from 5 to 8 years with a possibility of a partial review after 4 years.

Innovation – which might include not only technological developments but also the implementation of new operational processes or commercial arrangements, etc. – will be supported through two mechanisms. First, the longer-term, output-led, incentive-based, ex-ante price controls committing to companies the potential rewards that they could earn from successful innovations and committing not to penalize for unsuccessful innovations. Second, partial financing for innovation projects will be provided, awarded based on competitive processes. Required funds are planned to be raised from use-of-system charges which in turn are recouped from consumers. They will be treated as a pass-through cost in the price controls of the regulated companies. For more information see Ofgem (2010, 2011).

3.2.2 Instruments to promote investments

There is also strong heterogeneity regarding the instruments used to explicitly promote new investments. Different instruments are available (see also Annex 1 for case studies):

- *Adaptation of the regulation of TSO revenues:* A (temporary) enhanced allowed RoR can encourage the timely delivery of investments. This is applied for example in Italy, where extra returns of 2 to 3% are provided for a specified period of time for different types of investment. This instrument has also been recognized as being a tool highly conducive to promote investments (ENTSO-E, 2011c). Moreover, the reduction of the depreciation period below the common 40 years for transmission cables or natural gas pipelines or the inclusion of assets under construction into the RAB (with an increasing share the closer the project is to completion) can be conducive to promote investments (e.g. East-West Interconnector from Ireland to UK where the Irish regulator adapted its regulation accordingly).

- *Exemptions*: Providing an exemption does not mean leaving an infrastructure 'unregulated' but rather "regulate it to the extent necessary" in order to encourage planned investments (see also Kessel et al., 2011). This could include an exemption from regulated third party access (rTPA) or granting the regulated TSO the right to keep (in addition to the regulated tariffs) a portion of congestion rents a new interconnector generates. Numerous inter-regional projects have been built with partial or full exemptions, for example the BBL gas interconnector between the Netherlands and the UK, many new-built liquefied natural gas (LNG) import capacities that became operational during the last decade, or the electricity cables Estlink between Finland and Estonia, BritNed between the Netherlands and the UK, the East-West Interconnector between Ireland and the UK, or the AC cable between Italy and Austria.

- *Use of congestion revenues for new investments*: According to Regulation 714/2009 Art. 16(6), revenues from congestion management mechanisms applied to interconnectors can be used to re-invest them into new interconnection capacities.[9]

9 Two other possible uses are specified: (1) to guarantee

- *Long-term capacity reservation*: The regulator might allow the investor to cover a substantial share of the new capacity through long-term contracts or even reserve a part for the project sponsors themselves. In the natural gas sector, open season procedures are a prominent tool to determine capacity needs. At many LNG terminals, 80-90% of the import capacity is dedicated to the investors.

- *Public (co-)funding*: Public money can be used to directly finance transmission projects as has been done for example for a bi-directional Belgian natural gas pipeline connecting Eynatten and Opwijk (co-funded through EEPR means) or the HVDC underground cable between France and Spain which has been financed using amongst others TEN-E funds of € 225mn and EIB loans. The new Energy Infrastructure Package as proposed in October 2011 will set the legal basis for financial support in the form of grants for "projects of common interest"; € 9.1bn are planned to be made available for energy infrastructures via a so called "Connecting Europe Facility" for the coming multi-annual financial framework (2014-2020).

When discussing instruments that can be used to explicitly promote infrastructure investments, it should be noted that an adequate rate-of-return, though being a key parameter regarding investment decisions, is not the only factor having an impact on the attractiveness of an infrastructure project from the investor's perspective. As already mentioned above, regulatory stability and the predictability of future revenues are key, too. Furthermore, stakeholder surveys have shown that current practices regarding permit granting cause non-negligible transaction costs (Yang, 2009; Roland Berger, 2011; 2011b) and typically last for more than 5-10 years, going even up to 20 years in some cases (Realisegrid, 2010, for the electricity sector). Local opposition clearly is one relevant factor here; authorization processes not following schedules set by law or the complete absence of any rules regarding their timing are others. This issue has been recognized by policymakers: The new Infrastructure Package will provide guidelines regarding the permit granting procedure for "projects of common interest" including the maximum duration of pre-application and statutory permit granting procedures, responsibilities of involved stakeholders and institutions and the requirement for NRAs to cooperate when multinational projects are involved.

the actual availability of the allocated capacity; and (2) to reduce transmission tariffs. The past has shown that national regulators pre-dominantly chose this last option. According to Kapff and Pelkmans (2010), € 11mn have been used for (1), the majority of € 1387mn for (2) and only € 270mn have been re-invested in 2007.

3.3 Current EU involvement and harmonization

The current EU involvement in the regulation of TSOs' allowed revenues is rather limited (see Table 1 for further details). It basically includes some forms of harmonization in regulatory practice, namely the rules on the unbundling of transmission systems and grid operators, rules on the use of congestion revenues resulting from the market-based allocation of (electricity) interconnection capacities, which might be taken into account when approving tariff levels, and the possibility to grant exemptions from rTPA.

Furthermore, some funds provided by European institutions are available to co-finance infrastructure projects (see also Hirschhausen, 2011, for an in-depth overview). The European Investment Bank supports infrastructure investments with low-interest loans-with a total expected contribution in the period 2007-2013 of € 28bn (EIB, 2009)[10]. Furthermore, the Com-

10 Besides low-interest loans, the EIB uses a number of other means to support the financing of infrastructure projects: the Trans-European Network Investment Facility (TIF) provides funding for priority TEN projects, the Structured Finance Facility (SFF) provides funding to projects having a high-risk profile, and some money has flown also into equity funds.

munity budget includes funds for "trans-European networks" which covers both TEN-T (transport) and TEN-E (energy). TEN-E funds amounted to € 70mn in the period 2007-2009 and were mainly used to co-finance feasibility studies (up to 50%). However, this TEN-E co-financing only represented a very minor share (> 1%) of total investments (EC, 2010c; Cambridge Econometrics, 2010). Another source of public money is the European Economic Recovery Plan (EERP, Regulation 663/2009) based on which € 2.37bn have been made available for electricity and natural gas infrastructure projects. It was a very successful initiative in the sense of having leveraged substantial private funding. The new Infrastructure Package (EC, 2011) will contain € 9.1bn dedicated to energy projects.

Table 1: Current EU involvement regarding the regulation of TSOs' revenues

Form	Rules regarding	Details
Definition of general underlying principles	- / -	
Harmonization with respect to the choice of regulatory instruments	Unbundling of TSOs	D2009/72/EC, Art. 9 [electricity] and D2009/73/EC, Art. 9 [gas]
	Use of congestion revenues	R714/2009 Art. 16(6): "... shall be used for the following purposes: (a) guaranteeing the actual availability of the allocated capacity; and/or (b) maintaining or increasing interconnection capacities through network investments, in particular in new interconnectors. If the revenues cannot be efficiently used for the purposes set out in points (a) and/or (b) [...], they may be used [...] as income to be taken into account [...] when approving the methodology for calculating network tariffs and/or fixing network tariffs."
	Exemptions for major new infrastructures	R714/2009, Art. 17 [electricity] and D2009/73/EC, Art. 36 [gas]: Major new infrastructures (interconnectors, LNG, gas storage facilities) may be exempted for a defined period of time from: rules on use of congestion revenues [electricity only]; unbundling as specified in D2009/72/EC, Art. 9 and D2009/73/EC, Art. 9; third party access; and tariff control through NRAs
EU instruments	Public funds	TEN-E, EIB loans, EERP, etc. used to (co-)finance infrastructure projects
	Proposed European Infrastructure Package	Proposed regulation [COM(2011) 658 final] Priority to 12 strategic trans-European energy infrastructure corridors and areas; rules to identify "projects of common interest" (PCIs) – regional expert groups and ACER will be responsible for monitoring their implementation; acceleration of permit granting process for these PCIs; rules for a harmonized energy system wide cost-benefit analysis based on which cost allocation shall be determined; some public funds available under Connecting Europe Facility

3.4 Recommendations regarding the future role of the EU

1// Does the current heterogeneity regarding <u>general price control mechanisms</u> hamper adequate investments?

Probably yes. The observed heterogeneity in general regulatory principles and the methodologies used to calculate the allowed revenue of individual TSOs probably does not hamper adequate investments in *national infrastructures* without a strong cross-border impact[11]. First, different regulations have their justification in individual sector characteristics, the histori-

11 In the electricity sector, every new line will to some extent impact electricity flows within the whole (interconnected) grid. However, there are clearly differences among projects with a pre-dominantly national versus a regional (or even European impact). For natural gas, this distinction is even more clear.

cal evolution of the regulatory design, national policy priorities, or national regulators' responsibilities and capabilities. Second, key parameters determining investment incentives are an adequate risk-reward ratio with the rate-of-return reflecting the risks borne by the investors and associated cost of capital (and also recent increases in financing costs as a result of the financial crisis), regulatory stability and transparency, all issues national regulators can properly address.

Cross-country comparability, however, has shown to be difficult due to the observed heterogeneity in national regulatory practices in terms of determining asset base and level of remuneration. This could make it difficult to attract funds from external investors needed to meet the substantial financing needs in the coming decades. Various studies have shown that the move towards decarbonization is technically possible and financially affordable for the society as a whole (e.g. ECF, 2010); but that the question of implementability in the sense of making necessary funding available still is not clear. Huge investment needs have to be satisfied if "2014", "2020" and "2050" shall be taken for serious and investment volumes for the coming decade will have to increase by 30% for natural gas and by 100% for electricity transmission compared to current levels (EC, 2011)[12]. Moreover, the economic climate during the current financial crisis still is hardly conducive to large investments. Every investment will have a lasting impact on a TSO's capital structure and credit rating[13] and internal equity from the TSOs' operating cash flows might be insufficient to meet the high financial requirements in the future. Even though TSOs do not seem to face financing challenges up to date, external investors might become an important source of funds in the mid-term future and will ask for attractive rates of return-on-equity.

Regarding *projects that have a regional (i.e. cross-border) impact*, however, differing national practices regarding the regulation of TSO revenues could actually hamper adequate investments. Given the fact that especially in the electricity sector we face an increasing need to build long-distance transmission lines, alternative possible transit projects might be in competition. This competition between corridors (and thus between TSOs from different Member States) can imply that the grid might be expanded where an investor gets a more favorable return instead of where it would be optimal from a social welfare perspective, i.e. where total costs are lowest. This potential problem is less severe in the natural gas sector. The decision on alternative supply routes is to a major extent influenced by non-economic (e.g. (geo-) political or supply security oriented) considerations – the recently opened Nord Stream pipeline is an illustrative example.

Moreover, national regulation providing solely incentives to reduce *internal* congestion might discourage cross-border investments. Diverging national regimes on the two sides of an interconnector may result in asymmetric interests for the investors involved in the shared interconnector project (see also Ofgem and CREG, 2011) and there also is the risk that in the

12 A recent study prepared by Roland Berger (2011) for the EC reports that about €200bn are required only for energy transmission projects 'of European interest', i.e. international lines, in order to meet 2020 climate and energy policy objectives. Half of this amount might not be realized due to delays in permitting procedures and general 'difficult access to finance and lack of adequate risk mitigation mechanisms'. See also EC (2011b) or Baker and Gottstein (2011) for further details.

13 The prevalent form of financing transmission projects is corporate financing (only some merchant interconnectors are realized via project finance); thus, new assets appear in the TSO's balance sheet. TSOs have to raise both additional equity and debt in order to maintain their credit ratings. Illustrative example: A typical TSO might have a debt-equity ratio of 70:30. If new funds do solely originate from the debt market, his leverage might increase to 80:20, which at the same time implies higher risk of credit default, which at the same time results in a lower credit rating. Thus, to maintain the credit rating and favorable financing conditions, additional equity is required, too.

case where the realization of a new interconnection project requires the reinforcement of national core networks, too many costs might be allocated to a new interconnector in order to reduce the costs to be borne by national end consumers.

Thus, what could be the possible future role for the EU?

- Regarding general price control mechanisms **we do see neither the need nor a sound justification for an EU-wide harmonization**. Heterogeneity among national regulatory practices does not hamper adequate investments into national infrastructures but might cause inefficiencies regarding long-distance transmission projects with cross-national impact. Any obligatory EU-wide harmonization in methodologies used to calculate allowed revenues, however, would have far-reaching implications and the cost of harmonization probably substantially exceed benefits[14]. Different regulations also have their justification in individual sector characteristics, the historical evolution of the regulatory design, national policy priorities, or national regulators' responsibilities and capabilities, etc.

- We recommend only for projects with a clear pan-European focus that **decisions on the EU level should be taken** to avoid that higher-cost projects are built as a reaction to a more favorable RoR. Where a region-specific solution has to be found (e.g. offshore grid), decentral cooperation and coordination are appropriate. Besides, the ENTSOs' ten-year network development plans still do resemble more a collection of national investment projects rather than a portfolio including explicitly those new infrastructures that would be best from an EU perspective (see also Baker and Gottstein, 2011). The recently proposed Infrastructure Package (EC, 2011) is a basis specifying rules on the identification of "projects of common interest" (PCIs) and different measures easing and accelerating their successful implementation. It needs to be made sure, though, that ACER, when submitting its opinion on proposed PCIs to the Commission, follows a truly pan-European perspective and takes into account expected costs of proposed projects and identifies those of higher overall social value in case that there are alternative possible projects supporting the same strategic energy corridors. It also needs to be made sure that any discrimination among alternative projects is avoided.[15]

- Furthermore, it has to be underlined again that **transparency is of utmost importance**, not only to develop a level playing field, but also – if needed – to attract funds from external investors. ACER could play an active role in formulating "good practice guidelines" regarding the regulation of transmission grids, thus, to promote sound regulatory practices that try to minimize the risks for investors and to share 'best practice'; and in extending transparency (i.e. reporting) standards. Any convergence of the methodologies of regulating TSO revenues in terms of building the regulated asset base and determining rates-of-return will also help NRAs to evalu-

14 A sudden change in the regulation of TSOs will directly be reflected in these companies' value on the market; an agreement among 27 Member States on common accounting procedures and methodologies to value assets, etc. could not be reached easily and NRAs will try to protect the interests of national consumers challenging successful cooperation; etc.

15 A conflict of this kind recently occurred regarding a new gas interconnector between Spain and France (MidCat), competing with an LNG terminal on the French side. Both projects would require a reinforcement of the Rhone axis. Whereas no costs of this reinforcement would be allocated to the new LNG terminal, the MidCat project would have to bear 50% of this additional €500mn investment.

ate individual TSO performance. A second issue of transparency concerns the *communication of policy makers vis-à-vis end consumers*. It has to be made clear that the achievement of EU energy policy goals will imply – besides benefits from downstream demand response measures and increased energy efficiency – substantial infrastructure investments that will have to mirror in increasing transmission tariffs.

2// Does the current heterogeneity regarding instruments used to promote investments hamper adequate investments?

Probably not. Diversity of approaches to promote those investments that have a net positive value for the society as a whole can even be conducive to respond to the new challenges related to transmission grids. We are in a dynamic period, where neither the future energy mix, nor the availability of all technological solutions, cost structures, etc. are clear. Furthermore, every region differs in its specific characteristics and history of regulation and there is not the perfect 'one-size-fits-all' solution. Innovation in technologies, grid operation and market design needs innovation in regulatory tools. Thus, some diversity in regulatory practices can provide valuable insights into 'functioning' models and might allow to discover 'best practice' for specific situations. Thus, we do not see any need to harmonize instruments used to promote investments.

Also the observed heterogeneity regarding the *use of congestion revenues* resulting from the allocation of (electricity) interconnection capacities does not necessarily jeopardize adequate investments. There are some economic rationales for using congestion revenues to reduce tariffs. This will compensate those who suffered from congestion and avoid subsidies to third parties benefiting from an investment in the future. It also avoids the risk of funds being spent on uneconomic projects. However, other industry experts argue, in contrast, that a long-term increase in social welfare requires new infrastructure investments (see e.g. Kapff and Pelkmans, 2010; Glachant and Khalfallah, 2011). Supponen (2011) identified an overall social welfare potential of about € 1bn/a when interconnectors are optimally expanded. He also finds that especially for small transit countries that are situated in a high price gradient (Switzerland, Slovenia, and Denmark) a considerable share of transmission infrastructure could actually be financed through congestion rents. Accordingly, one might argue that – given the actual situation where the vast majority of congestion rents are used to reduce tariffs – it should be made sure that the rules as formulated in the Third Package are enforced[16].

Exemptions from rTPA and the limitation of TSO revenues should only be used as an instrument of last resort. There are many examples of successful realization of fully regulated projects where NRAs provide an appropriate return and involved TSOs could agree on a cost sharing rule that ensures that every party enjoys a net benefit. An example is the 700 MW Skagerrak 4 project, the forth DC electricity cable currently built by Statnett and Energinet.dk. The project will allow for an increased wind power production in Denmark and at the same time a higher export potential for hydro power from Norway in times of low wind potential. The investment costs of about € 400mn are shared among the two TSOs with the

16 The new Regulation explicitly puts more emphasis on new infrastructure investments than its predecessor Regulation 1228/2003; only in case congestion revenues cannot be used for options (a) and (b) it is envisaged to use them to reduce network tariffs. It has to be recognized, though, that TSOs will have little incentive to use congestion revenues to finance new infrastructures if national regulation does not allow for an inclusion of the respective assets into the RAB. Then, the companies face expenses (e.g. administrative cost during permit granting) but do not realize any corresponding profits from the investment.

Danish party bearing a bit more than 50%. Merchant gas and electricity lines can also only be a partial solution for promoting new investment. First, they are only an option where substantial price differences between zones appear (thus on the borders among a few Member States); and second, they will result in sub-optimal investment levels. It has to be avoided that exemptions are granted to projects that would also have been realized without this relaxed regulation. National regulators might be influenced by other than purely objective economic considerations and, in the case of LNG terminals, there might further be the risk that NRAs compete to attract merchant investments. Thus, the required approval by the European Commission and the possibility for ACER to provide an opinion on applications for exemptions are important institutional features.

In view of the predicted investment needs, innovative solutions to trigger investments should be considered to become common tools, too. The proposed *'cap and floor' model* for the planned subsea line NEMO connecting Belgium and the UK can be an interesting alternative to the exemption regime where at the same time risks for investors are limited, which brings down cost of capital. Returns above a pre-defined cap will be passed back to the national TSOs and will be offset against national transmission tariffs whereas for periods where returns are below the floor level, the interconnector owners will be compensated by the TSOs, who will recover the cost through national transmission tariffs. Moreover, the *competitive tendering* of infrastructure projects with incumbent TSOs and other investors competing for the development of identified priority projects by bidding a regulated income stream can be an interesting solution to minimize costs and thus consumer prices and to trigger an economically sound transmission expansion. This tool, introducing competition for the market where there cannot be competition in the market, has actually already proven to work in real world settings[17]. See also THINK (2012) for further elaborations thereon.

A *European tariff component* might be an interesting option to collect money from grid users that than could be re-invested into infrastructure projects of European value that suffer from strong externalities (i.e. building up a kind of regulated asset base paid for by an EU tariff component). The use of such an instrument has several advantages as compared to 'traditional' public funds: first, cross-subsidization is reduced since grid users instead of general tax payers are charged; second, demand elasticity for electricity and gas is considered to be relatively low. On the other hand, however, this instrument probably would be very difficult to implement and may lack public acceptance. Different levels of purchasing power in different countries will make the determination of a 'fair' rate problematic; in addition, the collection and redistribution of a big amount of money might lead to actors focusing on rent-seeking rather than trying to internalize the external effects through an adequate cost allocation. Furthermore, infrastructure projects will probably benefit certain regions more than others, and consequently, a European tariff component still implies cross-subsidizations between different regions.

3// Does current heterogeneity regarding the regulation of TSOs' revenues distort competition?

Probably yes. Discussions with different industry experts and stakeholders have shown that the issue of *heterogeneity in tariff levels*, even though not be-

17 See e.g. Baker and Gottstein (2011). The UK regime regarding the development of an offshore electricity grid allows interested parties to compete for the development of connection lines, and has, according to Ofgem (2011b), been successful in supporting market entry and the sourcing of funds. The regulator also estimates savings to be in the range of 350mn GBP for the first tender which had an overall value of about 1.1bn GBP.

ing regarded as the most critical issue since transmission tariffs only represent a minor cost factor in the consumer bill when compared to the value of the commodity itself[18], is a relevant topic. Montero et al. (2001) and in a following more extensive report Pérez-Arriaga et al. (2002) provide a study of *electricity transmission tariffs* in the EU 15 plus Norway and Switzerland. For a representative grid usage case, tariffs range between 2.97 (Sweden) and 8.84 €/MWh (Belgium). In-depth analyses of the data show that the volume of physical transmission assets can be satisfactorily explained by a number of parameters (i.e. total electricity consumption, country size, consumption per capita). However, the authors only found a poor correlation between the physical volume of transmission assets and transmission tariffs and conclude that unidentified explanatory factors must be of regulatory nature, namely employed methodologies to value the asset base and procedures of allocating transmission charges to different classes of grid users. A study conducted by ERGEG (2007) benchmarking *gas transmission tariffs* of six European TSOs led to similar results. Substantial differences have not only been identified regarding tariff levels but also in the way how different customers are charged. Exogenous factors including geographical and geological circumstances, physical specificities, market conditions, etc. can explain differences in tariff levels to some extent. Besides the above discussed exogenous parameters, transmission system operator efficiency of course also has an impact on tariff levels[19].

Thus, what could be the possible future role for the EU?

- In summary, besides various exogenous factors that are beyond the control of TSOs and differences in internal operating efficiency, heterogeneity in national regulatory practices leads to a situation where for the same volume of assets differing authorized revenues will be calculated, which in turn results in varying transmission costs and tariff levels. This can distort competition among generators from different Member States and might also have some impact on the competitiveness of energy-intensive industries. However, as already discussed above, it is very difficult for the EU to intervene and we do not see the need and/or justification of harmonizing the regulation of TSOs in the short- to medium-term. We recommend that ACER should take the responsibility for benchmarking national practices and formulate an opinion about the appropriateness of various methodologies employed.

4. Transmission grid tarification in the electricity sector

This chapter addresses the future role of the EU in electricity transmission grid tarification. National tariffs are a prerogative of Member States. However, electricity is a commodity that is traded internationally and, thus, a part of the costs originate from transregional flows and there is a second layer beyond national tarification to compensate TSOs for costs incurred as a result of hosting cross-border flows of electricity on their networks, the so called inter-TSO

18 In Germany for example, for industrial customers the share of transmission costs is about 7-8% for natural gas and about 12.5% for electricity (BNetzA, 2010).

19 Benchmarking the efficiency of transmission system operators, being a pre-condition for setting efficiency targets, is not a trivial task due to the small number of available observations. Cadena et al. (2009) discuss the suitability of standard efficiency analysis methodologies to determine efficient frontiers for electricity TSOs. Jamasb et al. (2007) develop a framework for the benchmarking of European gas TSOs. They argue that a comparison with US companies can produces robust results for relative efficiency across European operators, but that a common European strategy for data standardization would be an important step towards a valuable European benchmarking. For another proposed methodology of benchmarking gas TSOs considering explicitly the drawback of a small dataset see also Angenendt et al. (2007). Even though the share of controllable costs for TSOs is relatively small (CIEP, 2009) and efficiency improvements will only have a minor impact on the end consumer bill, benchmarking of TSOs is a promising measure bringing net social benefits.

compensation mechanism. We will also put emphasis on the need to find a sound mechanism based on which costs of major new infrastructures of European interest can be allocated to benefiting countries and TSOs.

4.1 Introduction

The role of transmission charges is to recover regulated network costs, which include an appropriate return on investment. Costs related to electricity transmission include (i) infrastructure costs (sunk investment costs as well as costs for operation and maintenance) and (ii) costs of *using* the infrastructure (losses, network constraints, ancillary services). In principle, costs related to infrastructure use can be recovered using market mechanisms (e.g. via auctions allocating limited line capacity). However, these revenues are not high enough to allow for complete cost recovery and residual network cost for a typical well-developed transmission network usually account for significantly more than 50% (Pérez-Arriaga et al., 1995). The same is true for market settings in which the difference in locational marginal prices is used to recover the cost of transportation[20]. Thus, transmission tariffs need to cover these residual network costs and at the same time should provide the right long-term investment signals (Rious et al., 2008).

20 Locational marginal (or nodal) pricing is a method of determining electricity prices with prices being calculated for a number of physical locations on the transmission grid called nodes. The nodal price is the marginal cost of supplying electricity at that node and represents the locational value of energy, which includes the cost of the energy, losses and congestion (Schweppe et al., 1988). The difference among nodal prices represents the short-run marginal cost of transporting electricity between the two nodes (Hogan, 1992). However, in actual reasonably well-developed networks as they exist in most countries, revenues from nodal prices will fall very short from recovering the total network costs due to strong economies of scale in transmission networks expansion, the discrete nature of investment, planning deviations and errors, and technical constraints such as reliability, etc. (Pérez-Arriaga et al., 1995).

It is important to clearly distinguish between short-run and long-run costs (Pérez-Arriaga et al. 2003). Short-run costs are mostly related to the use of the existing infrastructure; the parts of the tariff aimed at their recovery should send a signal for the efficient use of existing capacities (i.e. congestion management). Long-run costs, instead, are related to the investment in new infrastructure, and tariff components dedicated to long-run costs should provide a long-term signal for the location of supply and demand. The focus of our report is on the last, i.e. tarification in the narrow sense, excluding implicit (short-term) revenues for TSOs. We do not address the design of all mechanisms used to recover the cost for using the infrastructure. This is coupled with the design of the power market and an adequate analysis would require a detailed analysis of overall market design, which is beyond the scope of this report. We focus on *tariff structures*, rather than tariff levels, which are already treated in Chapter 3.

The following aspects are relevant for the design of electricity transmission tariffs in order to achieve the above introduced efficiency-related objectives:

1 - **Ensure adequate investments**:

- Although the tariff structure itself does not have any direct impact on TSOs' incentives to invest (into the grid or into e.g. RD&D), since these are determined through the regulatory scheme discussed above, it can directly influence (a) decisions regarding investments into upstream generation or downstream load if locational or power/energy signals are provided, or (b) decisions regarding facilities' operation if tariffs differ by season and/or between peak and off-peak periods, and, hence, can have an important impact on network development, the cost of new infrastructure, or consumer behavior and their choices regarding connection capacity. The increasing deployment of intermittent generation as well as increasing flexibility in demand are important factors to be considered when designing an appropriate regulation of transmission grids.

- With the ongoing integration of energy markets, an efficient trans-regional cost allocation supporting adequate investments plays a more and more important role.

2 - **Avoid any distortions in competition:**

- In view of the creation of an efficient single EU energy market, it is of utmost importance to design transmission tariffs in such a way that distortions in competition in the commodity market are minimized. This includes also that the part of tariffs recovering infrastructure cost, and thus not being related to the actual short-term use of the grid, shall not interfere with market actors' short-term decisions and bidding behavior in the power market.
- Furthermore, differences among national tariff structures should not distort competition among generators located in different Member States.

In the following, we assess whether the current regulatory practice regarding electricity transmission tarification, including both national tariffs as well as inter-regional compensation, is suitable to meet these objectives. In particular, we will investigate whether (i) the current heterogeneity in tariff structures does hamper adequate investments or distort competition and whether (ii) further EU involvement and harmonization beyond existing legislation are required.

4.2 Current regulatory practice

Numerous principles for tarification are discussed, including amongst others cost-causality, equity, or transparency. There are several conflicts among those principles; a perfect tariff system does not exist and real-world settings ask for trade-offs based on priorities among economic and political objectives (see Annex 2). Consequently, it is not surprising that we observe a wide heterogeneity in the current regulatory practice regarding electricity transmission tarification. A good overview on national transmission tariff structures can be found in ENTSO-E (2011)[21], for further details see also the TSO websites.

Table 1 shows the main characteristics of national electricity transmission tariffs. The **largest share is paid by consumers**; the L-component accounts even for 100% in the majority of Member States. Only a few countries apply also a non-negligible G-component, namely Austria, Finland, the UK, Ireland, Norway, and Sweden. Thus, many countries tend simply to socialize transmission costs among consumers. This is in part due to historical reasons (when transmission was still part of national vertically integrated utilities, transmission costs were in general simply socialized over all consumers, since under cost-of-service regulation and centralized planning it does not make sense to charge generators anything). The absence of any G-component obviously implies that there is no possibility to send any signal to generators regarding their impact on the cost of transmission.

Some countries give **locational and/or time signals** to grid users. In the UK, for example, the G-charge ranges between 25.59 €/kW in West Scotland and -7.20 €/kW in Central London with a weighted average 'transmission network use of system' (TNUoS) tariff of 4.56 €/kW. The L-charge ranges between 6.59 €/kW in North Scotland and 30.05 €/kW in Central London zone with a weighted average TNUoS demand tariff of 23.50 €/kW. Furthermore, Balancing

21 The ENTSO-E comparison takes into account tariffs that cover all cost of energy transmission and, given the large difference in tariff structures, data are provided for a basic scenario corresponding to: 5000 h utilization time that includes day hours of working days; the typical load considered is eligible and has a maximum power demand of 40 MW when connected at extra-high voltage and a maximum power demand of 10 MW when connected at high voltage; for countries with location signals, an average value has been taken.

System Use of the System (BSUoS) charges change daily.

Regulatory practice regarding **connection charges** varies widely among Member States. Connection charges might cover shallow or deep costs. Regarding shallow costs, which include the costs related to those network facilities needed to connect a single user, the beneficiary is clearly identified. For deep costs, including also the reinforcement of the core grid, this becomes more difficult. On the one hand, deep connection costs may be very high, on the other, beneficiaries typically include numerous (if not all) grid users. See also THINK (2012) discussing offshore grids. Whereas in some countries a new grid user only pays shallow costs, he has to bear also (all or some part of) costs related to the reinforcement of the core grid in other countries. There is, however, also some variation regarding to which user groups these are allocated. Furthermore, renewable generators may be exempted from paying a deep connection charge (e.g. Lithuania, partially also Hungary).

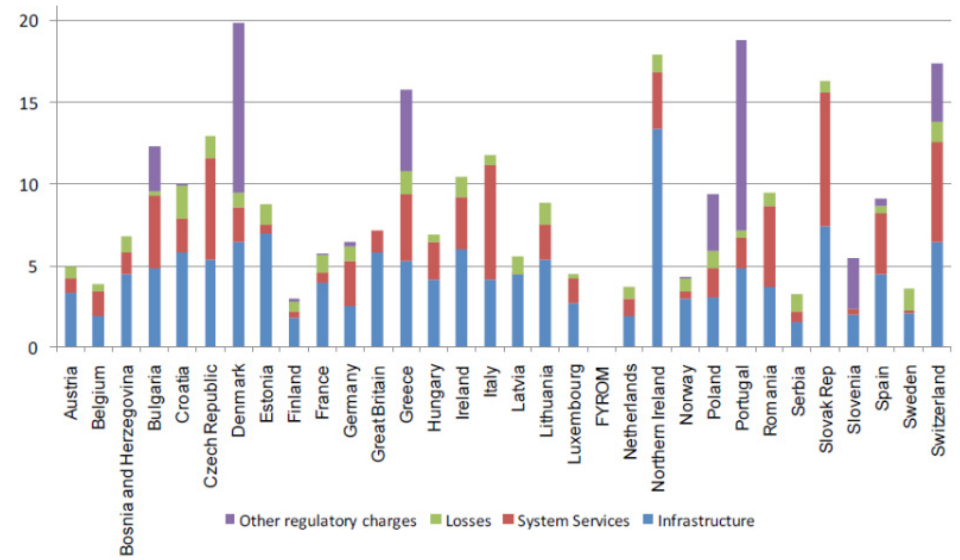
Table 2: Main characteristics of national electricity transmission tariffs

	Sharing of network operator charges		Price signal		Connection charge**
	Generation	Load	Locational	Time*	
Austria	15%	85%	-	-	Deep
Bosnia Herzegovina		100%	-	-	Shallow
Belgium		100%		Yes	Shallow
Bulgaria		100%	-	-	Shallow
Croatia		100%	-	Yes	Deep
Czech Republic		100%	-	-	Shallow
Denmark	4%	96%	-	-	Shallow
Estonia		100%	-	Yes	Deep
Finland	11%	89%	-	Yes	Partially deep
France	2%	98%	-	-	Shallow
Germany		100%	-	-	Shallow (generators) Deep (consumers)
Great Britain [TNUoS tariff]	27%	73%	Yes	Yes	Shallow
Greece		100%	-	Yes	Shallow
Hungary		100%	-	-	Partially deep
Ireland	25%	75%	Yes	-	Partially deep
Italy		100%	-	-	Shallow
Latvia		100%	-	-	Deep
Lithuania		100%	-	-	Deep
Luxembourg		100%	-	-	Shallow
Northern Ireland	25%	75%	-	Yes	Shallow
Norway	35%	65%	Yes	Yes	Shallow
Poland	0.6%	99.4%	-	-	Shallow
Portugal		100%	-	Yes	Shallow
Romania [refers to system services]		100%	Yes	-	Deep
Serbia		100%	-	Yes	Shallow (generators, distrib.) Deep (industrial consumers)
Slovak Rep.		100%	-	-	Partially deep
Slovenia		100%	-	Yes	Deep
Spain	6%	94%	-	Yes	Shallow
Sweden	25%	75%	Yes	-	Deep
Switzerland		100%	-	-	-

Source: ENTSO-E (2011)
[Notes: *time signals include seasonal and/or time-of-day variations; ** see the source document for more detailed specifications on which cost components are included]

Furthermore, tariffs do not cover the same **cost components** in all countries (see Figure 2). Costs from losses might be included in the tariffs or not, the same is true for system services, which also include the costs for balancing. Tariffs might also include costs not directly related to infrastructure such as other regulatory charges (e.g. support to renewable energy). This heterogeneity makes cross-country comparisons difficult and hampers transparency.

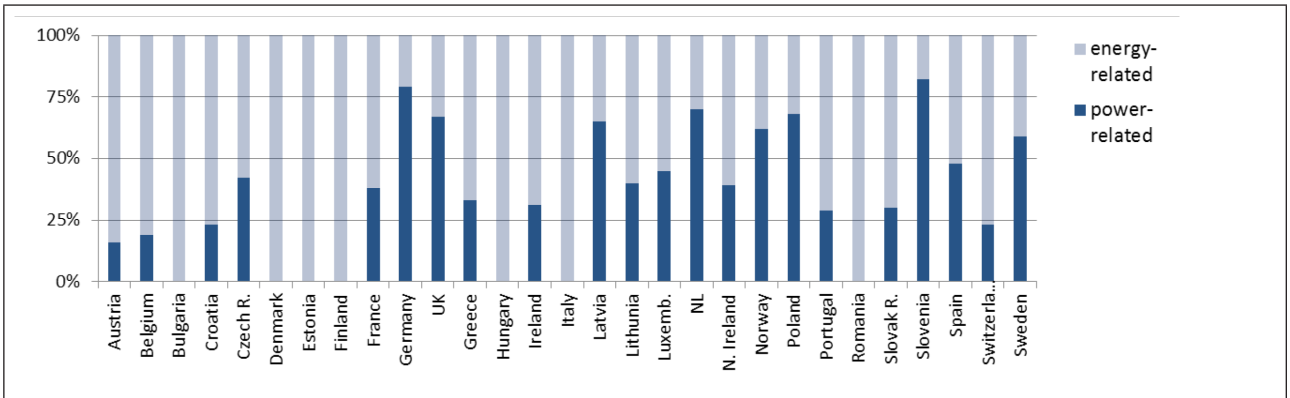
Figure 2: Components of transmission tariffs [€/MWh]



Source: ENTSO-E (2011)

Figure 3 shows the ratio in which tariffs are paid based on **energy- and power-related components**. There is wide diversity among national practices. Whereas in some countries the transmission tariff is fully paid based on energy transported (Denmark, Estonia, Finland, Hungary, Italy, Romania), the power-related component can go up to more than 75% (Germany, Slovenia). Tariffs paid per €/MWh, however, could distort the short-term behavior of market participants in the commodity market if not reflecting short-run costs related to actual infrastructure use.

Figure 3: Energy- versus power-related components of transmission tariffs



Source: ENTSO-E (2011)

4.3 Current EU involvement and harmonization

The current EU involvement regarding electricity transmission tarification in the narrow sense includes the definition of general underlying principles, some harmonization regarding the range of G-components as well as the inter-TSO compensation mechanism as an existing EU-wide instrument (Table 2). The European Commission recently also proposed a new Regulation in order to accelerate the realization of "projects of common interest". The following paragraphs will describe those in more detail.

Table 3: Current EU involvement regarding transmission charges on electricity

Form	Rules regarding	Details
Definition of general underlying principles	Charges for network access	R714/2009 Art. 14: "... shall be transparent, take into account the need for network security and reflect actual costs incurred [...] shall not be distance-related" "Where appropriate [...] shall provide locational signals at Community level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure" "There shall be no specific network charge on individual transactions for declared transits of electricity"
	Voluntary guidelines of good practice	E.g. on grid connection and access [Developed by NRAs (through CEER and ERGEG) to assist in practical implementation of principles set out in legislation; NRAs monitor and report on MS's compliance]
Harmonization with respect to the choice of regulatory instruments	Average charges paid by generators	R838/2010, Annex Part B : Range between zero and 0.5 €/MWh with exemptions for: (i) DK, SE, FI (0-1.2 €/MWh), (ii) RO (0-2.0 €/MWh), (iii) IR, UK, Northern IR (0-2.5 €/MWh)
	Exemptions for major new infrastructures from tariff control	R714/2009, Art. 17: New DC interconnectors may be exempted, for a limited period of time, from tariff control through NRAs (as well as from other provisions, not directly related to tarification, see above)
EU instrument	Inter-TSO compensation mechanism	R714/2009 Art. 13: An ITC shall compensate for costs incurred as a result of hosting cross-border flows of electricity R838/2010: Methodology to be used
	Proposed European Infrastructure Package	Proposed Regulation [COM(2011) 658 final] Priority to 12 strategic trans-European energy infrastructure corridors and areas; rules to identify "projects of common interest" (PCIs) – regional expert groups and ACER will be responsible for monitoring their implementation; acceleration of permit granting process for these PCIs; rules for an energy system wide cost-benefit analysis based on which cost allocation shall be determined; some public funds available under Connecting Europe Facility

4.3.1 EU involvement regarding tariff structures

Regulation 714/2009 defines the main principles for tarification. Charges shall be transparent and non-discriminatory. Even if cost-recovery is not explicitly mentioned, charges shall take into account "the need for network security and reflect actual costs incurred". Furthermore, "where appropriate, the level of the tariffs applied […] shall provide locational signals at Community level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure." Tariffs shall not be distance-related and any charges on individual transaction for the declared transit of electricity are precluded.

With the liberalization, an active debate among all European stakeholders regarding the need for tariff harmonization began. This brought as a first measure some harmonization of transmission charges to be paid by producers. Asymmetric G-charges would favor electricity export from countries with a lower G-charge (given that a substantial part of the charges is paid based on €/MWh of production), thus, hamper a level playing field for competition among generators across the EU. The harmonization of G-charges has been considered to be more important than a harmonization of the L-component since production from and the location of generation facilities are more responsive to price signals (ERGEG, 2005). Regulation 838/2010 fixes nominal upper levels for the G-component in national tariffs; the annual average transmission charge paid by producers shall be between zero and 0.5 €/MWh. For Denmark, Sweden and Finland this range is extended up to 1.2 €/MWh; for Romania up to 2 €/MWh; and for Ireland, the UK and Northern Ireland up to 2.5 €/MWh. ACER shall monitor "the appropriateness of the ranges of allowable transmission charges, taking particular account of their impact on the financing of transmission capacity needed for Member States to achieve their targets under the Directive 2009/28/EC" (Annex, Part B).

4.3.2 The inter-TSO compensation mechanism (ITC)

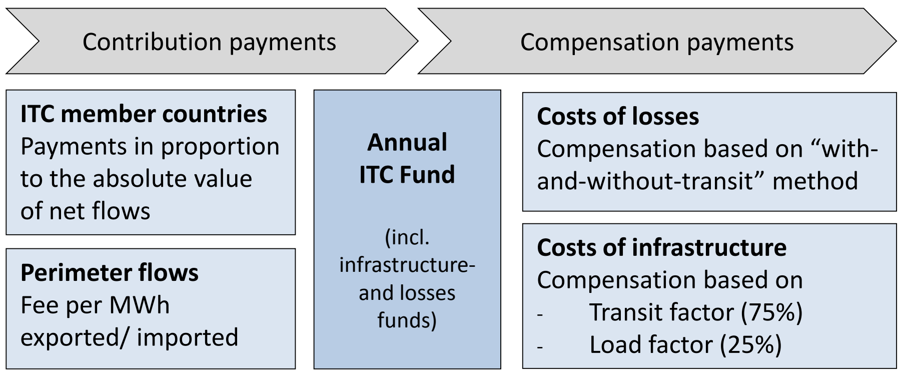
Before the liberalization of the European electricity sector, new cross-border infrastructures were developed through bilateral contracts while costs due to trans-national flows of electricity were recovered using a system of transit fees. The resulting "tariff pancaking" and the large difference in the structure and level of tariffs among Member States were soon considered main impediments for the implementation of a single EU electricity market (ERGEG, 2005). To abolish these cross-border tariffs, an inter-TSO compensation mechanism (ITC) was introduced in 2002 when eight European TSOs voluntarily signed a first ITC agreement. Since then, ETSO has continued to develop the mechanism and the regional scope quickly expanded (ETSO, 2009). With the Third Package and subsequent legislation, the ITC has been formalized as an EU-wide instrument. It is based on a hierarchical system: first, payments compensating for costs originating from cross-border flows of electricity are allocated among TSOs; second, TSOs take into account their net payments when determining national transmission charges based on national rules regarding tarification.

Regulation 714/2009 sets the legal basis for an obligatory inter-TSO compensation mechanism according to which TSOs are compensated for all the costs incurred as a result of hosting cross-border flows of electricity on their networks by those TSOs from whose systems cross-border flows originate or where they end. The costs shall be established *"on the basis of the forward-looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure […]"*. The concrete methodology currently applied is laid down in Regulation 838/2010. Its central element is an ITC fund which shall provide (separately calculated) compensation payments for (1) the ***costs of losses*** incurred in national transmission systems as a result of hosting cross-border flows of electricity; and (2) the ***costs of making infrastructure available*** to host cross-border flows.

The ITC is a zero-sum game with the fund being calculated and distributed annually based on an ex-post analysis. Contributions into the fund are determined based on TSOs' *"proportion to the absolute value of net flows onto and from their national transmission system as a share of the sum of the absolute value of net flows onto and from all national transmission systems"*. Thus the larger the imbalance between import and export flows of a country, the larger will be its payment into the fund. Perimeter flows contribute to the fund paying an annually, ex-ante defined fee for their imports and exports of electricity into the ITC area[22].

Regarding compensation payments a distinction is made between the above introduced cost components. A so called framework fund is established to manage compensation for the cost for making infrastructure available. ACER shall make a proposal on the annual sum based on a *"technical and economic assessment of the forward-looking long-run average incremental costs […] of making such electricity transmission infrastructure available."* Until this assessment has been carried out, the fund is fixed at € 100mn. The fund is distributed among TSOs according to a transit factor (75% weight) and a load factor (25%)[23]. For the cost of losses, the size of the fund is given by the sum of the costs of losses incurred in the national systems. Historical numbers show that it typically has been at a level of about € 120mn. Losses are estimated using a "with-and-without-transit" method for 72 defined snapshots during year. The base scenario refers to the real network flows in the relevant period; the other scenario refers to the flows that would have occurred if no transits of electricity had taken place. Costs due to losses are calculated at national level using the methodology approved by the NRA.

Figure 4: Current European ITC mechanism



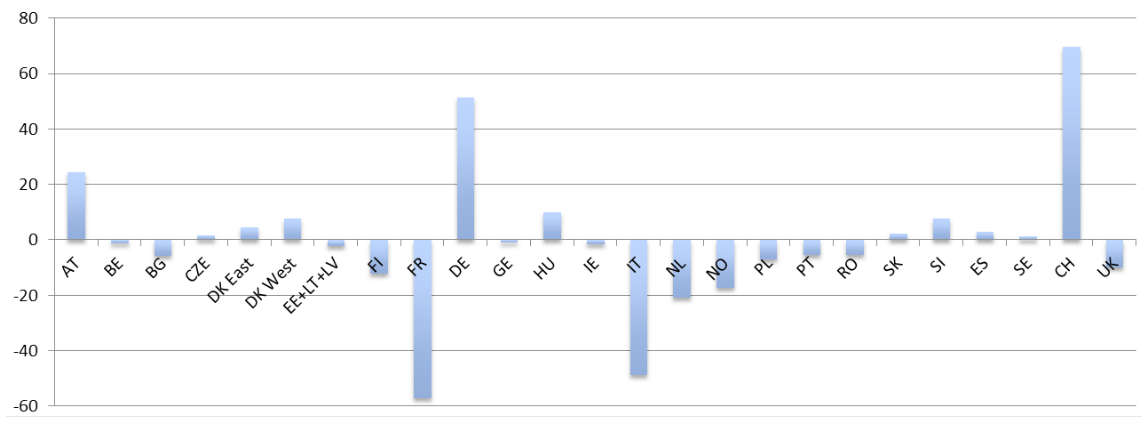
Source: Own depiction

22 The perimeter fee for 2011 has been set at € 0.8/MWh (ENTSO-E website).

23 The transit factor refers to transits on that national transmission system state as a proportion of total transits on all national transmission systems; the load factor refers to the square of transits of electricity, in proportion to load plus transits on that national transmission system relative to the square of transits of electricity in proportion to load plus transit for all national transmission systems.

Figure 5 shows data on the ITC settlements for 2008/2009 (most recent data currently publicly available). Even if the mechanism has changed with the new Regulation, these numbers provide valuable insights since, to our knowledge, the underlying methodology remained similar. Countries being net payers are those that are major importers or exporters of electricity, such as France, Italy, or Norway. Countries receiving net payments are typical transit countries such as Switzerland, Austria, or Germany.

Figure 5: ITC settlements in 2008/2009 [M€]



Data source: EC (2008)
[Negative values indicate net contributions into the fund; positive values net payments out of the fund]

4.3.3 The proposed European Infrastructure Package

In October 2011, the European Commission proposed a new Regulation aiming at improving the coordination of network development and accelerating electricity, natural gas, oil and CO_2 infrastructure investments in 12 "strategic trans-European energy infrastructure corridors and areas". The new Regulation, replacing the existing TEN-E framework, will set rules on how to identify "projects of common interest" (PCIs), whose timely implementation is essential to support the achievement of EU energy policy objectives. These projects will typically involve more than one Member State via physical location and/or via a significant cross-border impact. PCIs will be selected in a two-stage process: first, the project promoter(s) submit a proposal to the relevant "regional expert group" (being composed of representatives of Member States, NRAs and TSOs), which will prepare an initial list. Then, the Commission will take the final decision. ACER will be responsible for monitoring and evaluating project implementation.

A "harmonized energy system-wide cost-benefit analysis" for PCIs, taking into account social, economic and environmental costs and benefits, is a core element of this proposal. Concrete methodologies will have to be developed by ENTSO-E and ENTSO-G, respectively, and have to be approved by the Commission taking into account the opinion of ACER. Based on this, the costs for PCIs shall be allocated according to the (direct and indirect) benefits occurring in different Member States and will be paid for by grid users through national tariffs for network access. NRAs shall take a joint decision on the allocation of investment costs to be borne by each system operator. If they do not reach an agreement, "the decision on the investment request including cross-border cost allocation […] as well as the way the cost of the investments are reflected in the tariffs shall be taken by ACER."

If a PCI suffers from higher risks for the development, construction or operation, national regulators "shall ensure that appropriate incentives are granted to that project". In case a PCI encounters "significant implementation difficulties" the Commission may nominate a European coordinator. If the commissioning of a PCI is delayed by more than two years without sufficient justification, the Commission may launch a call for proposals open to third parties to build the project according to certain conditions. The proposed Regulation furthermore sets minimum standards for transparency and public participation and fixes a maximum allowed duration for the permit granting process in order to accelerate project realization. Finally, the proposed Regulation specifies the conditions under which PCIs might be eligible for financial support in the form of grants. Public funds of € 9.1bn will be available for the energy sector under the Connecting Europe facility for the period 2014-2020.

4.4 Recommendations regarding the future role of the EU

1// Does the current heterogeneity in tariff structures hamper adequate investments or distort competition?

Probably yes.

Transmission tariffs should be allocated as far as possible based on the principle of cost *causality*. This is important not only for the reason of fairness but, in a context of liberalized markets, also for economic efficiency. In fact, under the economic assumptions of the absence of any market power and perfect information, the maximization of global surplus can be achieved by a tariff system where the costs for network infrastructure are allocated to those who cause them or benefit from the assets (Pérez-Arriaga et al., 2003). It also implies that transmission tariffs should be able to transfer a locational signal; network costs depend on the location of generators and load[24].

With the liberalization of the electricity sector, a debate about a possible introduction of locational signals at European level through the harmonization of G- and L-charges was initiated. At this time, however, this was not considered appropriate for two reasons (ERGEG, 2005): first, because of uncertainty related to how efficient and accurate this signal could be; and second, because of the risk that a locational signal can distort short-term signals and thus distort competition in the power market. We think that now, given the context of the 2014/2020 targets, these two objections to locational signals are not justified anymore. The scale of investments needed in the coming decades and their correlation with generators' siting decisions is such that, even if there is no consensus on what is the best methodology to apply, the effort is justified. Regarding the second point, all tariffs that cover the cost of infrastructure, and not only the locational component, should not distort the short-term behavior of grid users.

The cost causality principle should be applied using a sound *cost-benefit analysis* that takes into account all relevant costs and benefits, including also externalities (Baldick et al., 2007; Hogan, 2011). In practice, however, it will be technically difficult to allocate network cost in an exact manner to beneficiaries and some proxy may have to be used (e.g. power flows). Olmos (2006) provides an overview on alternative algorithms and their suitability depending on specific characteristics of the power systems. There are increasing returns to scale and because lines cannot

24 In addition to tariff for recover the cost of infrastructure, a locational signal may also be sent with mechanisms used to recover the cost for using infrastructure, as congestion management, loss factor or nodal pricing (CEER, 2003; CESI, 2003). For example, the expectation of a poor energy price in a node where a potential investor is considering locating is an important locational signal for the siting decision. Thus, both locational transmission charges and expected nodal prices (when they exist), are valid and comparable locational signals.

be expanded incrementally but only in discrete steps, a new transmission line will typically only be used at a part of its capacity during the initial years of operation. Furthermore, some infrastructures are built for security and reliability reasons (such as N 1 condition). Moreover, the quantification of benefits can become very complex and a too sophisticated approach might not always be justified. These residual costs then need to be socialized (Olmos et al., 2009).

In many countries, transmission tariffs are completely paid by consumers and only a few countries have introduced locational signals, even though their importance has also been highlighted in Regulation 714/2009. This can actually result in inefficient investments. In the coming years, Europe needs a lot of investments into the network in order to allow for the connection of renewable energy sources and support the completion of the internal market. The cost for network reinforcement will also critically depend on the location of new generation (and load). It is important that investors when deciding on the location of new generation take into account transmission costs and there are strong arguments in favor of introducing locational signals EU-wide. Otherwise, they will tend to ignore incurred transmission in the siting decision, with the risk of overall high costs for the society.

Locational signals should be sent at least to *new generators*. The signals will not have any impact on incumbent generators with respect to 'adequate investments' since the respective production facility and grid investments already have been realized and are sunk in nature. They neither can be undone, nor can assets be moved. However, they will have an impact also on existing generators once they approach the end of their economic lifetime and can incentivize a relocation of utilities' power plant portfolio in the long-run. Locational signals can also be introduced for downstream players, even though their impact would mainly be limited to large consumers. Transmission tariffs have little influence on consumer behavior since transmission costs represent only a small share of the total electricity bill and demand elasticity is considered to be low.

The long-term locational signals need *to be efficient and accurate*. This implies that TSOs should implement a sound methodology respecting as far as possible the principle of cost-causality (or 'beneficiary pays') as discussed above. Tariffs also should send predictable and reliable signals such that the investors do not suffer from another source of uncertainty, i.e. the tariff *trajectory should be defined ex-ante* for a period of a few years.

A low, or completely absent, **G-component** has often been justified by the argument that all cost paid by the generator will be passed through to consumers anyway. This is only partially true. When making a decision whether to invest or not, a generator will estimate his expected rate-of-return, including the transmission charge as an additional cost. If, even with the transmission charge, the RoR is favorable because the generator has some advantages over competitors, he will absorb the transmission charge. Thus, if generators can absorb a part of the costs it is neither fair nor economically efficient to charge consumers alone. In order to have a locational signal for generators, obviously a certain share of the tariff needs to be paid by generators. To avoid a distortion in competition, some degree of harmonization regarding the G-component is needed. If some countries apply a charge to their generators but others not, the former weaken the position of their utilities in the European electricity market. Differing principles of calculating the G-component will hamper competition, not the magnitude of a G-component itself. Current harmonization on EU-level regarding the G-component concerns only its average maximum level that countries can apply. We think that, in addition, the EU should also fix an average share of the G/L components, thus, introduce a minimum G-component, too[25].

Tariffs could also send an ex-ante **time signal** to better account for the utilization pattern of different kinds of users, reduce overall peak demand and thus overall capacity needs and system costs. This would imply that the time-distribution of power produced by the generator (or respectively electricity consumed by load) are taken into account for tariff calculation[26]. Whereas locational signals do matter more for the location of new generators than for load, a time variation in transmission tariffs will have a direct effect on the consumption behavior of downstream users and can have an impact on the optimal dimensioning of the transmission network. Generators will not respond to time signals (given the absence of storage) since electricity generation will have to meet whatever demand there finally is.

There is wide heterogeneity also regarding the payment structure of tariffs. In many countries, network charges are to a large part recovered via energy-related tariffs (e.g. **€/MWh**). However, tariffs that cover the cost of infrastructure should not distort the short-term behavior of grid users. The costs of infrastructure are long-term costs. Thus, the way a TSO recovers those should only influence the long-term decision of grid users and should not interfere with their short-term behavior in the energy market (Pérez-Arriaga, 2003; Pérez-Arriaga and Smeers, 2003). Consequently, transmission tariffs covering infrastructure costs should not be charged in the form of €/MWh. This would influence the merit order since network users will internalize these charges in their energy bids to power exchanges or in their bilateral contracts (Olmos and Pérez-Arriaga, 2009). Tariffs for the cost of infrastructure instead should be paid based on booked capacity (€/kW per year) or lump-sum (€ per year), computed separately for different types of grid users in different areas reflecting the impact on grid capacity requirements, and so that charges duly reflect the diverse characteristics of each power plant[27].

Transparency is an important principle for tarification, also required by EU legislation (Regulation 714/2009), and will become even more important as the European energy market gets more integrated. However, we observe a lack of transparency regarding the elements included in network tariffs (Sakhrani et al., 2010). It should be clearly distinguished between network tariffs (i.e. costs for building and operating the grid) and other regulatory charges (e.g. including

25 Of course, the locational signal will not be the only factor determining the siting of new facilities. Other key drivers include resource availability, land costs, or also public opposition that can hamper the construction of power plants near consumption centers where locational signals will be low (or even negative). Moreover, heterogeneity in the level of connection charges, the duration of the permit granting process or renewable support has shown to drive investors' decisions about where to locate generation and which national network to connect into (CEER, 2011b). See also CESI (2003).
One also has to distinguish between the impact of locational signals on conventional and renewable generation. Especially renewable energy generators are not completely free in their siting decisions. However, transmission charges can represent a substantial part of overall cost (e.g. offshore wind) and a locational signal will support that decarbonization is achieved in the most cost-efficient manner; any reduction in transmission charges will reduce the need for public subsidies.

26 Short-term time signals (e.g. differentiation depending on the time-of-the-day) will be less important for investment recovery or planning but instead are more relevant for the short-term efficiency of the use of the existing network. One should equally note that short-term signals can also be introduced through short-term mechanisms for efficient usage of the grid (e.g. congestion and losses arrangement).

27 In fact, charging in the form of uniform €/MW, even if it does not distort short-term signals in the commodity market, runs into the problem of charging a peak load plant, which operates only few hundred hours per year, the same as a base load plant. However, charges should be calculated taking into account the grid user's characteristics; i.e. a 'per-MW' charge for a generator operating a nuclear power plant would differ from the one of a peak unit (i.e. low load-factor generator).

renewable support, costs of regulatory authorities, etc.) with the last to be charged for independently from transmission tariffs in a clear and transparent manner. Costs covering e.g. balancing should be allocated to the costs of electricity generation. Transparency in tariff composition is also a precondition to undertake an analysis of the impact of heterogeneity and to apply necessary regulation, both on national and EU level.

Thus, what could be the possible future role of the EU?

- A first area of harmonization concerning electricity transmission tariff structures shall be to increase transparency, i.e. to clearly define which cost components transmission tariffs should contain. They should only include cost related to transmission network infrastructure and exclude any other regulatory charges. This is a precondition to establish a level playing field for the grid users in different countries.
- Second, it should be ensured that the behavior of grid users in the competitive sector is not distorted due to tarification, i.e. transmission tariffs covering infrastructure costs should not be charged based on energy transported but instead be paid based on booked capacity or lump-sum, computed separately for different types of grid users in different areas so that charges properly reflect the network-related relevant characteristics of the network users.
- Third, transmission tariffs should be allocated as far as possible based on the principle of cost causality[28]. Locational signals should be introduced. Given that no 'best method' to be used has been identified yet, we do not recommend a harmonization of the methodology applied to calculate locational signals. Instead, it is important that decentralized solutions applied consider the national system specificities and follow the above discussed principles (i.e. sound methodology based as far as possible on cost-causality, with ex-ante signals to especially new generators). The provision of time signals to improve the short-term efficiency of the use of the existing grid should be considered, too.
- Finally, in order to give economic signals to generators, obviously a certain share of the tariff needs to be paid by generators. In order to avoid distortion of competition, we recommend some further harmonization regarding the G-component. The EU should also fix an average share of the G/L components; thus, introduce a minimum G-component, too.

2// Are the existing EU instruments targeting cost allocation well designed to support adequate investment and competition?

Probably not.

The **ITC** is a well-established mechanism with a transparent methodology that has been applied for about ten years; it is a binding EU instrument applying to all Member States. Its major success was to eliminate "tariff pancaking" which facilitates efficient cross-border trade – and thus is an important step towards "2014" – whilst simultaneously introducing a financial mechanism for compensating TSOs for the costs incurred from cross-border flows. Nevertheless the **current design of the ITC mechanism has a number of weaknesses** that hamper the effectiveness of the instrument.

First, the methodologies used to calculate the cost of

28 This applies also for the connection of new grid users. If the distance to the existing grid is small, shallow connection costs should be directly paid by the new user. If it is large and/or if the new facility serves supply security or is e.g. a large-scale renewable plant, the same cost allocation as for the existing transmission grid should be used.

losses and of making the existing infrastructure available have several limitations:

- The "with-and-without transit" methodology applied to determine costs of losses has a drawback in the definition of the "without scenarios". In a hypothetic scenario without any transit the national infrastructure would be different from the one actually in place, which is not considered. Moreover, given that the definition of transit is arbitrary, the "without transit" scenario could result in an impossible flow pattern, with disastrous implications for the ITC calculation. And in addition, the algorithm to calculate the scenario without any transit depends on the location of political borders. This is somewhat problematical as power flows solely obey the laws of physics and do not relate to administrative borders (FSR, 2005; Olmos and Pérez-Arriaga, 2007).

- According to Regulation 714/2009, the inter-TSO mechanism should compensate TSOs for cost incurred for hosting *cross-border flows*, but the methodology is based only on *cross-border transaction.*[29] While a cross-border flow is the measured power flow that crosses the borders, a cross-border transaction is the power flow that affects a nation's grid and that originates or ends in other grids. Using the cross-border transactionis problematic because it is technically hard, if not impossible, to identify transit (while it is easy to calculate cross-border flows). There is not an indisputable method in order to define if the flows caused by a national or by international agents and several definitions of transit are possible (Stoilov et al., 2011; FSR, 2005).

- The current ITC covers only selected network costs (i.e. infrastructure and losses), e.g. costs for system services are excluded from the scheme, although some stakeholders have provided arguments for the inclusion of other types of costs (ETSO, 2006).

- Cost allocation is determined based on the 'user-pays principle'. The implicit assumption, however, that those who use the new transmission asset are always the beneficiaries has to be proven.

- Methodologies used to calculate contributions into the fund and compensation payments are not coherent and, therefore, even though the individual calculation methods are transparent, the link between who causes cost and who pays for it is not clear (Stoilov et al., 2011).

Second, the ITC has been designed as an ex-post instrument compensating for the costs incurred as a result of hosting cross-border flows. It does not take into account investments in new infrastructure. The ITC methodology is based on an analysis of past transit flows and does neither include any cost-benefit analysis for new projects, nor does it take into account important benefits such as international trade, congestion rents and reduced costs associated with security of supply or maintenance (Androcec et al., 2011). It does not have any link with the EU network planning process (i.e. the ten-year network development plans published every two years by ENTSO-E based on national investment plans). Besides, the current size of the fund with € 100mn is very small compared to the expected cost necessary to support the development of the EU electricity network, and actually also compared to the costs of existing infrastructure.

29 There is some ambiguity in the EU regulation between 'flow' and the 'transaction'; in fact there is not a definition for 'hosting cross-border flows'. Regulation 1228/2003 states that "the compensation shall be paid by the operators of national transmission systems from which cross-border flows originate and the systems where those flows end".

The allocation of cost for new infrastructures with cross-national impact, however, is a key aspect in the context of the 2014/2020 targets, where interdependence between regions is increasing. The more the energy sector is integrated, the larger will be externalities generated by new infrastructures. A trans-regional cost allocation mechanism that does not internalize them in a reasonable way will fail to generate adequate investment incentives in the network on national level and can disturb competition among agents in different Member States. Still today TSOs basically rely on bilateral agreements for investments in new cross-border lines, with the cost in general divided equally between the two TSOs involved (Supponen, 2011). Bilateral contracts work well if the main beneficiaries of the project are within the two countries, which historically has often been the case for interconnectors. However, with the creation of the internal European market, highly meshed networks and the integration of large-scale renewable generation, beneficiaries of transmission investments are increasingly located in several countries and projects are not equally desirable for all concerned parties. If more than two stakeholders are involved in a project, contracts become very complex. Thus, **a common mechanism to determine cross-border payments for new investment is required** where benefits are spread across regions (or even the EU as a whole). This mechanism should be linked to a planning procedure and allocate costs to beneficiaries taking into account different stakeholder groups and also external effects (Hogan, 2011; Riechmann, 2011). See also Box 3 for international experience regarding inter-regional compensation mechanisms.

The **proposed infrastructure package** will address several of these issues; it actually has many good features: The regulation asks for an ex-ante cost-allocation method for new infrastructures "of common interest". It is worth noting that these infrastructures do not only comprise cross-border lines, but also national facilities that have an indirect impact on third Member States. The underlying ex-ante cost-benefit analysis shall take into account possible externalities. TSOs shall cooperate to develop the planning strategy while national regulators shall cooperate to allocate costs for PCIs. Network cost shall be paid through tariffs for network access and EU funding only be used for projects that are "commercially not viable". However, besides the fact that especially the quantification of benefits of grid expansions is not a trivial exercise, there are uncertainties about the implementation and effectiveness of the infrastructure package. Several issues need to be addressed in order to remove eventual barriers for the successful implementation of PCIs:

First, there is a <u>legal barrier</u>. National regulation does not allow TSOs to include investments realized in third countries in the own asset base (Supponen, 2011). An illustrative example could be a new cable within Germany that might benefit mainly e.g. Poland and the Netherlands. However, Polish or Dutch TSOs might first not be allowed to invest in Germany and second, their national regulations do not foresee the inclusion of any assets on foreign territory into their RAB. One possible solution solving this issue could be the financing of respective infrastructures through a European tariff component. Supponen (2011) also proposes an alternative solution, namely *the bundling of projects with trans-national interest into packages*, which also will explicitly be allowed by the new Regulation[30]. Building packages of projects that benefit all concerned stakeholders might

30 Southwest Power Pool in the US already has some experience with a similar approach. Portfolios of grid investments are built such that they benefit each zone within the SPP region. Costs are recovered on a postage stamp basis. If a particular zone does not directly benefit from a portfolio, a proportion of its transmission cost responsibility is fold into the portfolio to ensure that benefits exceed overall costs for all zones. See also Baker and Gottstein (2011) for more details.

facilitate agreements for cost allocation. It is always easier to allocate 'positive money' to people than to ask people to take money out of their pocket; the implementability seems more promising in a win-win game. However, the package conception itself will not allow us to completely by-pass the dispute over the individual projects, especially given the fact that the projects should be different in scale, timing, welfare distribution effect, etc.; the key issue will still lie in the implementation of sound cost-benefit analysis and allocation methods. There might also be the risk that projects are chosen such to find the 'right balance' among different TSOs instead of looking at the maximized overall EU benefit.

Second, the proposed Regulation specifies that in case the concerned national regulators do not reach an agreement on an investment request, ACER "shall take decisions" regarding the allocation of costs as well as the on how these costs are reflected in the national tariffs. This decision will be submitted to the Commission. However, it is not clear if ACER or the Commission have the legal power to step over national regulators and to enforce decisions regarding cost allocation, the regulation of national TSOs, and tariff setting.

Third, even though the proposed Regulation says that "national regulatory authorities shall ensure that appropriate incentives are granted", it does not provide any stimulus to national regulators themselves to do it. In other words, if the regulators do *not want* to provide incentives to TSOs to expand their grids, they are not forced to do so, and if they want to give incentives, existing legislation already allows them to do. In fact, the allocation of costs is always prerogative of national regulators and it remains to be doubted whether national regulators will fully cooperate voluntarily for increasing total EU welfare, especially in those cases where increasing interconnection capacity will have a substantial impact on consumer surplus due to rising energy prices. Therefore, an important role for the EU could be to incentivize NRAs rather than going into details about how regulators should incentivize TSOs.

Forth, congestion rents are not mentioned at all in the proposed regulation. However, congestion rents emerge due to bottlenecks at cross-border lines, which constitute a major reason for developing new infrastructure to accommodate cross-border exchange to the maximization of the total welfare for the interconnected countries. Therefore, these should be taken into account in the cost-benefit allocation mechanism, either being used directly to pay the new infrastructure, as suggested by existing legislation, or to reduce national tariffs, to compensate the least benefitting Member States for contributing in the construction of the new infrastructure.

Finally, the incremental cost allocation as proposed in the infrastructure package is not economically sustainable in the long-term. With every new asset the impact of former investment projects on stakeholders will change, which is especially true for the electricity sector. If we would like to make a comprehensive optimal planning for the EU grid, we need to have a vision of the optimal plan in terms of both space (regardless geographical boundaries) and time (regardless the order of the investment). A portfolio of investment projects, as already mentioned above, actually could avoid the cost-benefit analysis on single projects, which can be seriously biased by the sequence of the investment projects.

Thus, what could be the possible future role of the EU?

The current ITC mechanism only allocates cost resulting from hosting cross-border flows of electricity.

It was successful in abolishing 'tariff pancaking', but it was not designed and it is not adequate to allocate the costs for new and expensive large transmission infrastructure projects. However, to ensure market integration and the move towards a decarbonized economy, the timely realization of projects of regional interest is key. A sound cost allocation method is needed. The proposed infrastructure package is an important step into this direction; nevertheless we identified potential barriers for its successful implementation. Therefore, we provide the following recommendations:

- **The role of ACER and the Commission** regarding the enforcement of the development of PCIs and in the inclusion of the respective costs into the national tariffs **needs to be clarified**. In addition, given the uneven distribution of benefits among stakeholders arising from increased interconnection capacities and the concern that national regulators tend to protect consumers from rising prices, effective means have to be found to **incentivize NRAs** to support the development of identified priority projects. One option could be the harmonization of regulatory decision making by forcing NRAs to strictly consider pan-European (instead of national) benefits. However, this very strong solution will be difficult to implement. Similar outcomes can be achieved by ensuring the definition and application of sound ex-ante cost-benefit analysis and allocation methods overcoming the problems identified above and supporting the implementation of an EU-wide transmission expansion plan.

- The EU should call for the **removal of the legal barriers** that might impede grid investments where strong geographical asymmetries in costs (i.e. investment needs) and benefits occur. It is necessary that third parties can invest where incumbent TSOs do not show interest to realize identified priority projects (see also the above notice on competitive tendering in Chapter 3.4). Those who wish to take action should not be forbidden to do so. Actually, as a positive side-effect of such a regime, the need for ex-ante cost-benefit allocation arrangements for such projects would be reduced.

- Regarding the **existing ITC**, the EU should consider **adaptations of the methodology** applied to compensate TSOs for the costs occurring from hosting cross-border flows of electricity in order to overcome drawbacks identified above.

Box 2: International experience with inter-regional compensation mechanisms

US practice in a nutshell

The US electricity market is separated into three non-synchronized zones: the Western and Eastern Interconnection and the Electricity Reliability Council in Texas. Within the Interconnections, there are several electricity markets operated by Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). To facilitate the comparison with the EU, the Eastern Interconnection is electrically of the same order of magnitude as the EU-27 and RTOs can be likened to large EU Member States. The US has not yet developed cost allocation rules or planning procedures at interconnection level. A recent

MIT study (MIT, 2011) advocates for interconnection-level planning and cost allocation, and stronger federal siting powers. The network belongs to several transmission owners (TOs) for each market. FERC regulates the wholesale market and interstate transmission while retail markets, intrastate transmission and cost approval of new transmission infrastructure are with individual state regulation.

Most ISOs and RTOs use a hybrid approach for interstate cost allocation, spreading some cost over peak MW to load while other costs are allocated to beneficiaries using flow-based methods. Individual practices vary widely across the country. Costs might – at least in part – be allocated based on the principle of cost causality (e.g. New York ISO, Midwest ISO) or socialized among a larger consumer group (e.g. Southwest Power Pool, where projects that benefit customers on a regional basis are combined to a portfolio and the respective costs of an implemented balanced portfolio are recovered through a postage stamp kind of tariff; see Baker and Gottstein (2011) for more details). FERC Order 1000, issued in July 2011, supports cost allocation to actual beneficiaries; it requires transmission providers to participate in a regional transmission planning process that has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan. Cost allocation methods can be developed decentrally in the individual regions, but have to satisfy a number of cost-causality-related principles (FERC, 2011).

PJM as a case study

PJM Interconnection is an RTO in the Eastern Interconnection for the area from Chicago to the east coast (including 13 States and D.C.) and covers a market with 58 million people and a peak demand of about 158 GW. Its responsibility is to ensure reliability within the control zone, the operation of the wholesale market, planning of generation and transmission for reliability, and independent and neutral system operation (PJM, 2011). TOs cooperate with PJM in the planning process (Regional Transmission Expansion Plan - RTEP). The interstate system planning is regulated by FERC but transmission tariffs are recovered on state level. This requires a sound set of rules for cost allocation among states as the investment costs have to be approved by state regulators.

For the interstate cost allocation, PJM distinguishes reliability from economic upgrades. For <u>reliability upgrades</u> the costs of line upgrades are allocated to load:

- For lines 500 kV and above, costs are socialized with each state paying according to its share in peak load;
- For lines below 500 kV, a flow-based method once determines a cost distribution factor for each state which considers the contribution to flows on the constrained facilities;
- Cross-border investments between PJM and MISO (two RTOs) are also allocated regarding their contribution to flows on the line.

For <u>economic upgrades</u>, other methods like monetary metrics can be applied. However if the benefit-to-cost ratio exceeds a certain value (e.g. 1.25) the upgrade is included in the RTEP and is treated like reliability upgrades. Thus, in the PJM market cost allocation between states is connected to the transmission planning and its methodology decided based on the characteristics of the transmission line (PJM, 2010).

5. Transmission grid tarification in the natural gas sector

This chapter addresses transmission grid tarification in the natural gas sector. Similar questions will be asked as in the previous discussion on transmission tariff design for electricity. However, answers might differ since these two commodities and their markets, besides many similarities, show a number of substantial differences as has been pointed out also in Chapter 1. When investigating concrete issues related to gas transmission tariff structures and the potential need for EU involvement and harmonization we highlight these factors explicitly.

5.1 Introduction

As already introduced above, (regulated) transmission tariffs have the role to recover the TSOs' regulated costs and to allocate costs to grid users. Entry- and exit charges thus need to be designed such that the sum of ex-ante set tariffs applied to transported volumes and auction revenues originating from the allocation of interconnector capacities approach as much as possible the expected, allowed revenue. Tariffs can further be used to provide valuable economic signals. Our analysis again focuses on the design of tarification in the sense of *tariff structures*, rather than tariff levels, which are treated in Chapter 3.

The following aspects are relevant for the design of natural gas transmission tariffs in order to achieve the above introduced efficiency-related objectives:

1 - Ensure adequate investments:

- The key factor determining TSOs' incentives to invest in the grid is the allowed rate-of-return, as has been discussed in-depth above. The *tariff structure*, in turn, can have an impact on grid investments in the sense that locational signals to grid users can support efficient up- and downstream investments and thus are a relevant factor for the minimization of overall system cost.

2 - **Avoid any distortions in competition:**

- A bad design of transmission tariffs and divergent regulatory practices might hamper competition and efficient (cross-border) trade, e.g. due to the incompatibility of capacity products offered in neighboring countries, charges that are designed such that they distort the market behavior in the commodity market, etc.

Analogously to the previous chapters, we investigate whether (i) the current heterogeneity in regulatory practices regarding natural gas transmission tarification hampers adequate investments into the grid or distorts competition and, if yes, (ii) whether further EU involvement and harmonization beyond current legislation are required.

5.2 Current regulatory practice

The regulation of tarification in the natural gas sector is under national responsibility and a certain decision power also is with TSOs themselves. This decentralized decision making has resulted in a wide heterogeneity in current practices. In the following, we summarize key parameters of the current regulation of natural gas transmission grid tarification and highlight differences among Member States. For more details see Kema/Rekk (2009), and TSOs' and regulators' websites.

The Third Package sets the rules for an obligatory, EU-wide, decoupled entry-exit system. Shippers can book entry- and/or exit capacities independently and pay separate entry- and exit charges for grid usage.

Trade within one entry-exit zone (i.e. a zone of a single price for the commodity) shall be completely flexible. The calculation of network charges on the basis of contractual paths (point-to-point model) won't be allowed anymore. Nevertheless, persisting heterogeneity regarding the stage of implementation and the concrete design of this model of tarification for natural gas transmission grid access can still create some obstacles to efficient (cross-border) trade and functioning competition:

First, **flexibility of the decoupled entry-exit system in some Member States is reduced** due to several reasons. Some countries still distinguish between domestic transport (applying the entry-exit model) and transit flows (applying distance-related point-to-point models where entry- and exit capacities are coupled, which in turn reduces market liquidity as compared to a system concentrated around a single (virtual) hub). This problem will disappear since with the implementation of the Third Package, the calculation of network tariffs based on contractual paths will not be foreseen anymore (see R715/2009 Art. 13(1)). Flexibility is further reduced if regions (or even Member States) are divided into several market areas even though the absence of any technical reasons, i.e. where the networks are connected with each other and also gas quality does not differ. The recent past has already seen a move towards a reduction in the number of sub-national market areas; e.g. in Germany, their number has fallen from 19 in 2006 to two in 2011. In France, the gas market has seen a reduction of zones from seven (2003) to three (2009). And also for Belgium, where currently four prize zones exist, a merger to a single entry-exit zone covering the whole country is under consideration.

Second, **only a part of the countries have introduced transmission tariffs that are differentiated by location** via distinct entry- and exit charges (e.g. UK). The absence of locational signals, however, implies that transmission tariffs do not adequately reflect the costs caused by grid users and that instead costs are socialized. This in turn results in an inefficient infrastructure use and the possibility of actively providing locational signals for feed-in and/or load is missed. This will be less consequential for small price zones; however, a well-interconnected system with several alternative sources of supply and maybe even some flexibility in flow directions could clearly benefit from locational signals.

Third, there is **heterogeneity regarding the splitting of costs (allowed revenue) between entry- and exit points**. A number of countries apply a sharing rate of 50:50 (e.g. Italy, UK)[31]. In Portugal, tariffs are calculated based on long-run average incremental costs using a simplified model of the transmission system with a resulting entry-exit split of 26:74. Belgium allocates only fixed costs, equaling about 15% of the total allowed revenue, to entry points using a system 'km-equivalents' where an average distance of 136km is taken into account for domestic trade and actual distances for transit flows[32]. The Czech Republic actively wants to promote imports and market entry and therefore applies a cost split between border entry- and exit points of 22:78.

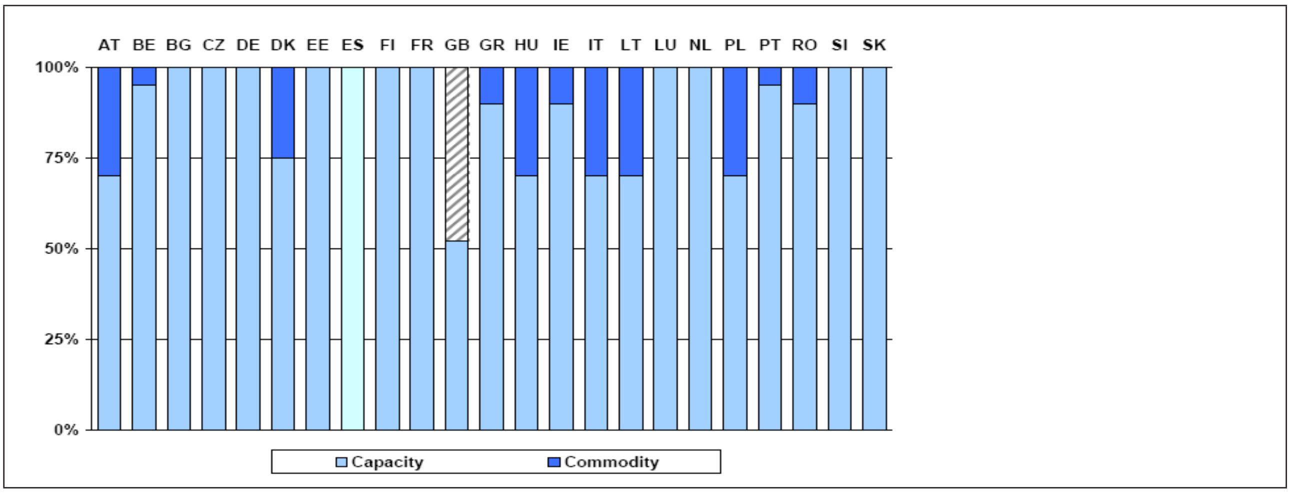
31 A part of the entry- and exit capacities in the UK are allocated via auctions. Reserve prices are calculated based on the long-run marginal costs of transporting the gas from and to these points at peak conditions (using the distance from each entry point to the system reference node and respectively from the reference node to the exit point). Revenues are adjusted through an additional (transmission owner) commodity charge to (i) maintain the 50:50 split and (ii) to ensure a minimum reserve price and cost-recovery.

32 The allowed revenue is divided by the total amount of capacity and the km-network-length, resulting in a 'basic cost per unit of transmission' of 0.147 €/(m^3/h)/km. There is one unified tariff for all entry points representing 15% of the total budget, or 41 km-equivalents, of 6 €/m^3/h. For entry/exit between zones, the transported distance is multiplied by the per-unit-costs. For border exit points, a charge of 2 €/m^3/h and for domestic supply exit points a charge of 14 €/m^3/h apply.

The breakdown of costs between entry- and exit points mainly has an impact on the possibility to use those charges to set locational signals through grid use tariffs, i.e. in an extreme situation where the full costs are recovered through exit charges (similar to a zero-G-charge system in the electricity sector), there is no room for any incentive setting on the supply side. However, in contrast to electricity, natural gas production to a much larger extent takes place far from the consumption centers (the EU-27 incl. Norway and Switzerland faced 40% import dependency on a Member State level in 2010; see BP, 2011); on average, a cubic meter of gas passes two borders before final consumption. Thus, congestion at entry points can be a very relevant issue.

Fourth, similar to the electricity sector, **varying importance is given to capacity- and commodity-based tariff components** (see Figure 6). These shares also vary within countries by consumer type (e.g. for Hungary between 60-80%), depending on contracted volume, maximum capacity use and load factor (see ERGEG (2007) for some numeric examples). Furthermore, it is **not obvious which cost components are included in the commodity charge**. In Italy, for example, the capacity charge shall cover capital costs (depreciation and remuneration on invested capital) while the commodity charge shall cover operating costs; fuel gas is provided by shippers. Some TSOs require the network users to compensate for the corresponding volumes of fuel gas and/or shrinkage (e.g. UK) whereas others apply separate charges (e.g. Ireland). Only for a number of countries, these costs are part of the basic transmission tariffs (e.g. Belgium, where the commodity charge of around 5% covers the fuel gas).

Figure 7: Split between capacity- and commodity-based components in gas transmission tariffs



Source: Kema/Rekk (2009)

Finally, there is **wide heterogeneity regarding the capacity products offered** and their pricing. Besides conventional longer-term capacity products, *interruptible capacity* is offered by most TSOs; however, mainly applied to inter-zonal trade and natural gas storage and production sites. Prices depend on the probability of interruption with a typical discount of about 10-30% (even much larger variance). *Non-physical backhaul capacity*[33] is only offered by the minority of TSOs. It may be offered for firm and/or interrupt-

33 Backhaul capacity = capacity into the opposite than the physical flow direction.

ible products; pricing mechanisms vary considerably including e.g. a discount on the price of the respective physical product, auctioning (UK), or no charge at all (Portugal). Inefficient pricing, contractual congestion and a lack of non-physical backhaul capacities hamper efficient cross-border trade and the completion of the internal market. The heterogeneity in capacity products offered also has several implications for the functioning of the market. Besides increased transaction costs, a mismatch of capacities available on both sides of a zonal border might result in additional 'capacity hoarding' since shippers need to contract more capacity than they physically need. This obviously becomes even more consequential as congestion (physical but also contractual) is a problem at many cross-border points.

5.3 Current EU involvement and harmonization

The current EU involvement in the tarification of natural gas transmission infrastructures includes the specification of general, qualitative, underlying principles for grid tariffs and third party access, the obligation to apply decoupled entry-exit systems, as well as the possibility to grant exemptions for major new infrastructures from tariff control. See Table 4 for further details.

Table 4: Current EU involvement regarding the tarification of natural gas transmission infrastructure

Form	Rules regarding:	Details
Definition of general underlying principles	Tariffs for network access	R715/2009, Art 13(1): "... shall be transparent, take into account need for system integrity and its improvement and reflect the actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator, whilst including an appropriate return on investments, and, where appropriate, taking account of the benchmarking of tariffs [...] ... shall be applied in a non-discriminatory manner [...] ... tariffs may also be determined through market-based arrangements, such as auctions [...] ... shall facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users and providing incentives for investment and maintaining or creating interoperability for transmission networks"
	Capacity products offered	R715/2009, Art. 14(1): TSOs shall provide both firm and interruptible TPA; both short- and long-term services R715/2009, Art. 14(2): Transport contracts signed with non-standard start dates or a shorter duration than a standard annual transport contract shall not result in arbitrarily higher or lower tariffs
	Voluntary guidelines of good practice	E.g. on use of exemptions, balancing, or open season procedures [Developed by NRAs (through CEER and ERGEG) to assist in practical implementation of principles set out in legislation; NRAs monitor and report on MS's compliance]
Harmonization with respect to the choice of regulatory instruments	Decoupled entry-exit system	R715/2009, Art. 13(1): "Tariffs for network users shall be non-discriminatory and set separately for every entry point into or exit point out of the transmission system [...] By 3 September 2011, the MS shall ensure that, after a transitional period, network charges shall not be calculated on the basis of contract paths"
	Exemptions for major new infrastructures from tariff control	D2009/73/EC, Art. 36: Major new infrastructures (interconnectors, LNG, gas storage facilities) may be exempted for a defined period of time from tariff control through NRAs (as well as from other provisions, not directly related to tarification, see above)
EU instrument	- / -	

5.4 Recommendations regarding the future role of the EU

1// Does the current heterogeneity in tariff structures hamper *adequate investments*?

Probably not. Adequate investments into transportation infrastructures might be challenged, however, by the substantial uncertainty regarding the future role of natural gas in a decarbonized economy and thus about demand and infrastructure needs. See e.g. EC (2010b) illustrating alternative gas demand scenarios up to 2030. Hence, getting downstream utilities involved in the realization of large-scale supply infrastructures to make them financeable is one key issue. Yet, we do not see any active role of the EU here. Required expansions of the European network – both national grids and cross-border infrastructures – should be less problematic: First, measures to reduce and prevent contractual congestion, which is much more relevant for most interconnection points than physical congestion (see also CIEP, 2009), need to be fostered. Second, an adequate regulation of TSO revenues as discussed in Chapter 3 will provide the right incentives to reinforce the grid and invest in new supply infrastructures. Third, the complexity of projects involving more than one TSO is much lower than in the electricity sector since commodity flows can be measured and controlled. This makes regional, multi-lateral agreements regarding the allocation of costs feasible. In addition, the issue of supply security seems to be treated quite well through bilateral agreements and Regulation 994/2010, and investors are compensated for those investments that show substantial positive externalities. The role of the EU here should be limited to monitor and accelerate the implementation and enforcement of this Regulation and to support regional cooperation via e.g. mediating between NRAs' with diverging (i.e. national) interests.

One issue, however, might become more relevant in the longer-term perspective when market areas are further merged into larger prize zones and the number of bi-directional pipelines rises. In well interconnected systems with liquid markets, alternative supply sources and well-functioning competition, price differentiation among entry- and exit points reflecting the costs caused by system users can provide valuable locational signals and reduce the share of costs socialized among all customers. Two issues have to be noted, however: First, the impact of locational signals will be quite limited. For upstream players, other factors (such as the geographical location of gas sources or the availability of potential new LNG sites) in many situations might be more decisive. On the downstream side, only a small sub-set of consumers has some flexibility regarding the siting decision. Second, efficient economic signals indicating bottlenecks can be derived also from allocating cross-border transmission capacity through auctions, as has been proposed by ENTSO-G recently in the draft network code on capacity allocation mechanisms.

2// Does the current heterogeneity of regulatory practices *distort competition*?

(2-1) From (sub-) national entry-exit zones to a pan-European price zone?

There are **more than 30 entry-exit zones** whose size tends to be based on administrative borders rather than technical or economic considerations. Typically, a price zone coincides with an 'operating zone' managed by a certain TSO and reflecting the historically developed market structure with national (or even sub-national) grid operators. Thus, they are not all of an '**optimal size**' and the process of merging market areas continues to be an issue. Given the policy goal of achieving a single European gas market, larger zones have some obvious advantages, such as an increase in market liquidity and possibilities to trade, increased short-term trade and price alignment, and the reduction of price distortions due to contractual (and price) pancaking (see also Glachant, 2011).

Of course, one single pan-European price zone theoretically is possible, though not necessarily desirable since an increase in the size of market areas entails various drawbacks, too. The creation of large price zones, leads to economic inefficiencies: (i) first, *intra-zonal constraints are not subject to different prices anymore* and re-dispatching and/or countertrading managed by the TSO are required instead. Thus, prices become less cost-reflective; the costs of congestion are socialized among a larger number of grid users and; cross-subsidies increase. With an increase in the size of a price zone, less locational signals revealing capacity constraints will therefore be provided. See LECG (2011) for an in-depth discussion of this phenomenon as well as of further market distortions resulting from persistent intra-zonal constraints; (ii) second, within the new price zone, the *free allocation of capacities shall still be sustained* at the same time that supply security and system stability are maintained. There are technical constraints for offering decoupled entry- and exit capacities; an increase in the size of the market area means that further bottlenecks and possible flow scenarios will be included, which in turn reduces available firm transport capacities. Past mergers actually have led to a reduction of offered capacities at entry- or exit points (see Thyssengas, 2011) or the transfer of former firm into interruptible capacities[34]; (iii) and third, combining market areas operated by different TSOs probably will result in additional costs resulting from an increased need of cooperation.

34 See ICIS/Heren (2011) for recent experiences in Germany after the merger of the Thyssengas H-Gas, Thyssengas L-Gas, Open Grid Europe L-Gas and the NCG market areas in April 2011.

Therefore, the further merging of market areas into regional zones has to be evaluated with care and on a *case-by-case basis* to see whether the economic benefits in the form of increased market liquidity, trading flexibility, etc. – which might be quite difficult to quantify (see also CIEP, 2011) – outweigh the above listed drawbacks. Since system architecture, supply and demand patters as well as contracting practices and institutional design differ across Europe, there is not one optimal size in terms of geographic dimensions or other descriptive factors. In any case, boundaries of price zones should reflect the technical and economic conditions rather than political borders. Besides, further emphasis needs to be put on complementary means fostering the internal market, namely an efficient design of capacity allocation mechanisms and congestion management procedures at interconnection points.

Merging price zones will obviously result in fewer available entry- and exit points. System operation has to be managed either under the lead of one independent regional system operator or in close cooperation between the respective TSOs. Once market areas are combined, there are alternative ways, how system operation and tarification can be organized, namely maintaining individual TSOs' tarification autonomy or moving to a new system of common tarification:

(1) Maintaining individual TSOs' tarification autonomy ("German model"): The German experience of merging market areas has not resulted in any harmonization of tarification among the concerned TSOs but instead left them full autonomy in tariff setting within the boundaries of the national regulatory scheme. Each TSO collects charges to recover his regulated costs from his remaining points; no monetary transfer occurs. The regulatory authority did not keep a fixed entry-exit split which allows for a more flexible tariff allocation. This model has developed out of

the historical situation with TSOs being responsible for tariff setting. Actually, minimizing the need for inter-TSO cooperation and coordination, and avoiding any harmonization of tariff design, this solution has been the easiest to implement.

This approach has two basic implications. First, tariff values in concrete interconnection points may be considerably different depending on the underlying tarification systems which might differ in entry-exit split, relevance of capacity- and commodity charges, etc. Second, due to the necessity to recover the costs from the smaller number of points post-merger, it results in substantial price increases at some entry and/or exit points. Hence, there might be points at which different TSOs hold capacities and the level of charges differs among these TSOs. This is less consequential as long as there is some congestion at these points. However, as soon as TSOs actively compete for customers, those who have to allocate higher costs to specific points are in a competitive disadvantage. Second, shippers on the one hand gain access to a larger market area; on the other, however, they have to pay higher prices. This is especially unattractive for those shippers who only transport gas to specific, near-to-the-border destinations. A re-distribution of cost bearing occurs.

(2) System of common tarification: An alternative option involves a complete restructuring of the system of tarification. In a first step, involved TSOs would aggregate their allowed revenues. Then, based on a common system of tarification, these would be allocated to the remaining entry- and exit points. Obviously, this procedure involves an agreement regarding a common design of tariff structures and principles of capacity allocation and congestion management. Tariffs could either be centrally collected by one responsible party (e.g. a selected TSO or a trustee) and redistributed to all TSOs according to ex-ante specified rules (i.e. in proportion to their share in the total allowed revenue) or they could be collected by all individual TSOs for their respective entry- and exit points and, based on periodical comparisons of target and actual revenues monetary transfers would make sure that each TSO achieves cost recovery[35].

The implementation of such a new pricing scheme would lead to certain price shifts among different points; some customers might be worse off (e.g. they might have benefitted from amortized infrastructures within their original smaller area but after a merger might have to pay for new grids now part of the enlarged price zone). The major challenge of introducing a system of common tarification, which would be desirable in order to avoid the above presented drawbacks of a system of individual TSOs with tarification autonomy, is to find an agreement regarding a common method. Such a harmonization apparently implies that the concerned TSOs have to find a compromise on the most suited approach and it can be expected that this won't be an easy-to-treat 'all-win' situation. In addition, the common tariff setting will abolish the possibility for single TSOs to compete for customers through offering more attractive pricing arrangements.

Thus, what could be the possible future role for the EU?

- The **EU should set principles for determining the ideal size of entry-exit zones, but let concerned NRAs and TSOs agree on the result**. As discussed above, the optimal model will involve

35 Remark: This mechanism should not be called inter-TSO compensation mechanism (ITC) since this term is closely related to the existing instrument used in the electricity sector to compensate TSOs for costs related to cross-border flows. The here described procedure is much less complex, involving mainly the collection and re-distribution of money according to rules that can much more easily be specified and agreed on ex-ante.

a number of regional (not one single pan-European) price zones, with the efficient boundaries being dependent on regional specifics (system architecture, supply- and demand patterns, etc.). In any case, boundaries of price zones should reflect the technical and economic conditions rather than political borders; mergers of market areas shall be evaluated on a case-by-case basis based on expected economic benefits and costs. This can best be done by the concerned NRAs in close cooperation with the respective TSOs since these are endued with the required deep understanding of system functioning.

- Once market areas are merged, there are good economic reasons to implement a system of common tarification, thus, to harmonize tariff design within the enlarged price zone. The role for the EU should be limited to support sound agreements between the respective stakeholders (e.g. as a kind of mediator during negotiations on which tarification system to implement) and to formulate principles of coordination. The actual implementation of harmonization of tariff structures and definition of a mechanism to compensate TSOs can be managed at regional level. A European-wide harmonization goes too far with costs (e.g. non-consideration of regional specifics, transaction costs of negotiations, etc.) probably exceeding the benefits. It shall be noted, however, that this approach where all customers of a market area pay for the aggregated costs of the TSOs evokes the question of a need to harmonize also the underlying regulation of TSO revenues.

(2-2) Barriers to efficient competition

There are some probable barriers to efficient competition. First, the existence of this large number of entry-exit zones implies tariff pancaking. It has to be reminded that in contrast to the electricity sector, where the 'copper plate paradigm' has been accepted as a basis for transmission pricing in Europe, natural gas is transported over long distances and the commodity typically passes several entry-exit zones before being delivered to final consumers as already mentioned above. Furthermore, the grid is substantially less meshed with mainly uni-directional flows that are well controllable and assignable to shippers. Hence, transmission tariffs completely independent of the transported distance are not legitimated here and instead the pancaking in principle does make sense to reflect the cost of transportation that increases with distance.

Regarding '**price pancaking**', the conclusion of successive contracts would be unproblematic from an economic perspective as long as charges are cost-reflective and theoretically, the sum of all entry- and exit charges would equal the transmission charge that would have to be paid if there was one pan-European price zone. However, this is not fully given in reality since tariffs might be slightly above true cost to ensure cost recovery; they might include socialized costs not reflecting the shipper's actual grid use and the need to enter a large number of contracts also implies high transaction costs for shippers (see also GTE, 2005; LECG, 2011). Furthermore, the problematic of '**contractual pancaking**' for long-distance transmission persists, i.e. shippers are typically interested in booking capacity from a specific source to specific destination without being particularly interested in intermediate interconnections.[36]

36 A multitude of auctions would be necessary to address all possible combinations grid users might be interested in. This issue is treated in-depth within the ongoing 'gas target model' discussions (see also Ascari, 2011; CIEP, 2011; Frontier, 2011; Glachant, 2011; LECG, 2011). Since this is out of the scope of this report, we will not go into any further detail here; however, we agree that a coordinated capacity booking procedure for long-term long-distance capacity bookings should be established.

Second, in entry-exit systems of grid tarification there is often a systematic bias in the form of a cross-subsidization between short-distance transmission and long-distance (cross-border) transportation (GTE, 2005; Kronfuss, 2009; CIEP, 2009). Tariffs at a specific entry point are equal for all grid users, independent on whether the gas is transported only a few km to the next local consumption center or a few hundred km across the whole entry-exit zone. Thus, **domestic consumers tend to cross-subsidize transit flows** and transmission over some hundreds of km can even be cheaper than transmission over 50km depending on the pricing at individual exit points. This effect becomes more severe the bigger the price zone; hence, is another factor limiting the optimal size of market areas due to economic inefficiencies and should be taken into consideration when evaluating mergers. Some countries (e.g. Italy, France, or the UK) have introduced so called 'short-haul tariffs' in order to adjust tariffs for short-distance transportation and to mitigate this distortion in competition (see also Kema/Rekk, 2009). In Italy, for example, there is a discount for gas transportation over distances of less than 15km; shippers pay 1/15 times the distance in km times the standard tariff.

Third, as discussed above, there are **various other obstacles to efficient competition**, including contractual congestion, inefficient pricing of non-standard products such as interruptible capacity, a persisting lack of backhaul capacities, or the limited compatibility of capacity products offered. Furthermore, regarding short-term capacities (for natural gas this means a duration of less than one year) which need to play an even more vital role in the future to allow for short-term arbitrage between markets and to approach the completion of the internal market, there are intensive discussions about efficient pricing (see Box 4). On the one hand, too high tariffs represent a penalty on short-term trade, may hamper market entry and reinforce capacity hoarding and (contractual) congestion. On the other, target revenues should be attained regardless of the booking behavior of network users. Current UK practice, where the reserve price for short-term capacity auctions has a discount compared to the long-term products, has actually shown a shift from long-term towards short-term bookings. The resulting under-recovery of TSO revenues is corrected through an extra commodity charge applying on all entry tariffs. This causes additional distortions in natural gas trade since the commodity charge does not reflect any short-run marginal cost of system operation.

Ascari (2011), for example, describes an 'open subscription procedure', which is basically an extension and generalization of the open season process based on a common grid- and flow model.

Thus, what could be the possible future role for the EU?

- **Existing rules defined in the Third Package vis-à-vis TPA** regarding capacity products offered and the harmonization of contracts and related procedures (Annex I of R715/2009) need **to be enforced**. Accordingly, TSOs shall amongst others offer firm and interruptible services down to a minimum period of one day; harmonized transport contracts and common network codes shall be designed in a manner that facilitates trading and re-utilization of capacity contracted without hampering capacity release; TSOs shall implement standardized nomination and re-nomination procedures, and harmonize formalized request procedures and response times.

- The **implementation of the proposed Network Code on capacity allocation mechanisms** at interconnection points (ENTSO-G, 2011; see also Appendix 1) needs **to be fostered**. It proposes amongst others to allocate all firm and interruptible capacities using standardized auction procedures for standardized capacity products at defined points in time, with reserve prices reflecting regulated tariffs. Introducing '*revenue equivalence of booking profiles*' will ensure long-term signals for investments and avoid a shift from long- to short-term bookings. We furthermore want to stress that mechanisms used to correct for a potential under-recovery of TSO revenues resulting from the auctioning of capacities, should be designed such that they do not distort grid users' behavior in the market.

- We recommend some harmonization in natural gas transmission tarification to ensure that the **breakdown of costs among grid users and among entry- and exit points** is designed such that as far as possible the principle of **cost-reflectiveness** is respected. It has to be avoided that national end users cross-subsidies long-distance transportation. On the one hand, there should be adequate discounts on short-haul transports; on the other, an asymmetric re-allocation of costs such that 'captive' domestic consumers intentionally have to bear a disproportionately high share of overall costs, shall be prohibited.

- Furthermore, the EU, through ACER, should formulate a set of '**good practice guidelines' regarding natural gas transmission tarification**. Entry- and exit charges should be actively used to provide locational signals to grid users wherever this is economically reasonable. Furthermore, similar to the discussions above concerning tariff structures in the electricity sector, commodity-related components should reflect short-run marginal costs in order to avoid distortions in the behavior of shippers in the commodity market and network tariffs should clearly be identified, containing only those cost elements that are related to the transmission activity (i.e. infrastructure investment and operation).

Box 3: Pricing of short-term products – Too high? Too low?

Regulation 715 Article 14(2) contains principles regarding the pricing of short-term products: "*Transport contracts signed with […] a shorter duration than a standard annual transport contract shall not result in arbitrarily higher or lower tariffs that do not reflect the market value of the service…*"

Indeed, vital discussions about this issue are ongoing, also in response to the recent debates concerning adequate auction reserve prices for the different standard capacity products. If a resource is scarce, it is sufficient to define the bottom line price such that the market can be cleared (i.e. $p < MC$). The problem lies in off-peak periods. If the reserve price is at a too high level, it would impede traders to participate in short-term trade; if it is too low, cost recovery cannot be ensured and under-recovery has to be corrected ex-post (e.g. via an additional commodity- or capacity charge, a lump-sum payment, or the implementation of regulatory accounts for the TSOs).

Current practice in many Member States involves substantially higher prices for short-term products (see Kema/Rekk, 2009; ERGEG, 2011b) and there actually is some economic reasoning for a certain premium. Though, too high tariffs represent a penalty on short-term trade, may hamper market entry and reinforce capacity hoarding and (contractual) congestion; and obviously, prices not reflecting marginal cost will not deliver correct signals. Thus, some stakeholders argue in favor of low reserve prices based on the argument of possible welfare gains through the facilitation of short-term transactions, a more efficient use of the system and resulting price alignment between markets.

The draft network code on capacity allocation mechanisms pleads for the concept of '*revenue equivalence of booking profiles*' [i.e. regardless of the booking behavior of network users, the target revenues should be attained] and thus multipliers higher than one to a tariff determined from an annual accounting basis [i.e. reserve price for any shorter-term product shall aim to compensate for shortfall in sales volume]. This will ensure long-term signals for investments and avoid cross-subsidies from those grid users with rather flat transmission patterns from those with highly variable ones, since any discount on short-term products would result in a shift from long-term to short-term commitments. This effect will be even more consequential in systems being endued with planned overcapacities for reasons of supply security and/or where existing long-term contracts can be quit without strong penalty payments (as is the case both for e.g. Spain). There might be other system-specific factors that have to be taken into account when discussing optimal reserve prices for short-term products; e.g. UK regulation includes mechanisms that allow the transfer of unbooked capacity of one entry point to another one that faces excess demand; thus, grid users will have an extra incentive to secure capacity rights over the long-term.

Current *UK* practice allows for a discount in reserve prices for short-term capacity auctions compared to long-term products (33% for day-ahead and 100% for within-day auctions). This discount is supposed to reflect the relationship between short-run and long-run marginal costs grid users incur on the system. However, demand for longer-term capacity is indeed elastic and, thus, the UK saw a shift from long-term towards short-term bookings (which in this case also has been fostered due to the fact that the UK system has substantially higher total entry capacity [> 9000 GWh/d] than peak demand levels [~ 5000 GWh/d] what may encourage grid users to delay capacity bookings). This resulted in non-negligible under-recovery of TSO revenues which in turn is corrected by adding an extra commodity charge to all entry tariffs. The additional distortions in natural gas trade due to this commodity charge not reflecting any short-run marginal cost of system operation obviously are an obstacle regarding the achievement of "2014". In *Germany*, Thyssengas recently had to adapt its pricing structure as a reaction to decreasing long-term bookings at entry points. Entry charges have been reduced; charges at national exit points – where no zero-reserve-prices exist – substantially increased. This actually penalizes 'captive' domestic consumers and benefits shippers transporting gas across the market area.

6. Conclusions and recommendations

In this report, we have analyzed the possible future EU involvement regarding the *regulation of TSO revenues* and *transmission grid tarification* in the electricity and natural gas sectors. European transmission grids are facing new challenges that come from EU energy and climate policy. The two key objectives that any frame of regulation of TSOs and grid tarification should address in this context are to *ensure adequate investments* and to promote *efficient competition*. Analyzing current regulatory practices and EU involvement, we found a wide heterogeneity in regulation and tarification among the different Member States while the current EU involvement is rather limited. We asked (1) whether these heterogeneities hamper adequate investments or impede efficient competition and (2) whether new EU legislation in place and new EU instruments notably from the Third Package – *once enforced* – are suitable to support adequate investments and efficient competition. From the answers to those questions we derived our recommendations for future EU involvement and need for harmonization. In the following, we briefly summarize our main results and recommendations.

(1) Regulation of TSO revenues

Does the current heterogeneity regarding the regulation of TSO revenues hamper adequate investments or impede efficient competition?

Probably yes.

The observed heterogeneity in general regulatory principles and the methodologies used to calculate the allowed revenue of individual TSOs as well as instruments used to promote new investments probably does not hamper adequate investments in *national infrastructures* without a strong cross-border impact. Different regulations have their justification in individual sector characteristics, the historical evolution of the regulatory design, national policy priorities, or national regulators' responsibilities and capabilities. Key parameters determining investment incentives are an adequate risk-reward ratio with the rate-of-return reflecting the risks borne by the investors and associated cost of capital, regulatory stability and transparency, all issues national regulators can properly address. In addition, the current heterogeneity regarding instruments used to promote investments can actually provide valuable insights into 'functioning' models and might allow to discover 'best practice' for specific situations.

Cross-country comparability, however, has shown to be difficult due to the observed heterogeneity in national regulatory practices in terms of determining asset base and level of remuneration. This could make it difficult to attract funds from external investors needed to meet the substantial financing needs in the coming decades. Furthermore, differing national practices regarding the regulation of TSO revenues could actually hamper adequate investments regarding *projects that have a regional (i.e. cross-border) impact*. Competition between corridors (and thus between TSOs from different Member States) can imply that the grid might be expanded where an investor gets a more favorable return instead of where it would be optimal from a social welfare perspective, i.e. where total costs are lowest.

Finally, besides various exogenous factors that are beyond the control of TSOs and differences in internal operating efficiency, heterogeneity in national regulatory practices leads to a situation where for the same volume of assets differing authorized revenues will be calculated, which in turn results in varying transmission costs and tariff levels. This can distort competition among generators from different Member States and might also have some impact on the competitiveness of energy-intensive industries.

Are legislation in place and existing EU instruments, once enforced, suitable to support adequate investments and efficient competition?

Probably not.

The current EU involvement in the regulation of TSO revenues is limited to some forms of harmonization in regulatory practice, namely the rules on the unbundling of transmission systems and grid operators, rules on the use of congestion revenues and the possibility to grant exemptions from regulatory tariff control. Furthermore, the EU has some funds available to co-finance infrastructure projects. The recently proposed European Infrastructure Package – once enforced – will be a good basis to identify "projects of common interest" and specifies also different measures easing and accelerating their successful implementation. However, existing legislation does not solve all the problems listed above.

Thus, we recommend for future EU involvement:

- We do see neither the need nor a sound justification for an EU-wide harmonization of the regulation of TSO revenues. Such a harmonization would have far-reaching implications and the cost might substantially exceed the benefits. We recommend nonetheless that regarding projects with an important cross-national impact, decisions on the EU level – taking into consideration a truly pan-European perspective – should be taken to avoid that higher-cost projects are built as a reaction to a more favorable RoR. Where a regionally specific solution has to be found (e.g. offshore grid), decentral cooperation and coordination are appropriate.

- ACER should play an active role in formulating "good practice guidelines" regarding the regulation of transmission grids, thus, to promote sound regulatory practices that try to minimize the risks for investors; and in extending transparency (i.e. reporting) standards. ACER should also take the responsibility for benchmarking national practices and formulate an opinion about the appropriateness of various methodologies employed.

- In view of the huge amount of predicted investment needs, innovative solutions to trigger investments should be considered to become common tools, too, and legal barriers be removed. Competitive tendering for infrastructure projects can be an interesting solution. Also a European tariff component to collect money from grid users that than could be re-invested into projects of European value that suffer from strong externalities should be considered. Using public funds to (co-) finance infrastructure projects should be considered carefully.

(2) Transmission grid tarification in the electricity sector

Does the current heterogeneity regarding tarification hamper adequate investments or impede efficient competition?

Probably yes.

There is large heterogeneity in the tarification of electricity transmission grids. In many countries, transmission tariffs are completely paid by consumers and only a few countries have introduced locational or time signals. Energy-related tariffs are predominant which distorts grid users' short-term behavior in the commodity market. Tariffs do not target to recover the same costs in all countries and, in some cases, they also include costs not directly related to transmission infrastructure but targeting other regulatory objectives. The resulting lack of transparency makes cross-country comparisons difficult.

Are legislation in place and existing EU instruments, once enforced, suitable to support adequate investments and efficient competition?

Probably not.

While the EU has defined general principles of tarification, there is little EU involvement with respect to tariff design except for some harmonization of the maximal average G-component. The existing ITC mechanism is an ex-post instrument that intends to compensate TSOs for the costs resulting from hosting cross-border flows of electricity. Besides some methodological weaknesses, it has not been designed to incentivize the timely realization of grid investments or to allocate costs of new infrastructures. The proposed European Infrastructure Package will address these issues for projects of pan-European interest; however, we identified some factors that might hamper the successful implementation and effectiveness of this new Regulation.

Thus, we recommend for future EU involvement:

- A first area of harmonization concerning tariff structure shall be to increase transparency, i.e. to clearly define which cost components transmission tariffs should contain. They should only include cost related to transmission network infrastructure, but exclude any charges related to other regulatory objectives.
- It should be ensured that the behavior of grid users in the competitive sector is not distorted due to tarification, i.e. transmission tariffs for the long-term infrastructure cost should not be charged based on energy transported (i.e. in €/MWh) but instead be paid based on booked capacity or lump-sum, computed separately for different types of grid users in different areas so that charges properly reflect the network-related relevant characteristics of the network users.
- Transmission tariffs should be allocated as far as possible based on the principle of cost causality. Locational signals should be introduced, being calculated decentrally taking into account national system specificities based on sound methodologies and providing reliable ex-ante signals. The provision of time signals to improve efficient short-term use of the existing grid should be considered, too. To give economic signals to generators, obviously a certain share of the tariff needs to be paid by them. In order to avoid a distortion of competition, the EU might fix an average share of the G/L component; thus, introduce a minimum G-component, too.
- The EU should call for the removal of the legal barriers that might impede grid investments where strong geographical asymmetries in costs (i.e. investment needs) and benefits occur. It is necessary that third parties can invest where incumbent TSOs do not show interest to realize identified priority projects.
- Given the uneven distribution of benefits among stakeholders arising from increased interconnection capacities and the concern that national regulators tend to protect domestic consumers from rising prices, effective means have to be found to incentivize NRAs to support the development of identified priority projects.

(3) Transmission grid tarification in the natural gas sector

Does the current heterogeneity regarding tarification hamper adequate investments or impede efficient competition?

Probably yes.

Heterogeneity in tariff structures itself does not hamper adequate investments while it might certainly hamper efficient competition. First, there are more than 30 entry-exit zones with mainly administratively determined borders. Thus, they are not all of an 'optimal size' and the process of merging market areas continues to be an issue. The existence of this large number of entry-exit zones also implies tariff pancaking. Second, in entry-exit systems of grid tarification there is often a systematic bias in the form of a cross-subsidization between short-distance transmission and long-distance (cross-border) transportation and domestic consumers tend to cross-subsidize transit flows. Third, other obstacles to functioning competition include contractual congestion, inefficient pricing of non-standard products such as interruptible- or short-term capacity, a persisting lack of backhaul capacities, or the limited compatibility of capacity products offered.

Are legislation in place and existing EU instruments, once enforced, suitable to support adequate investments and efficient competition?

Probably not.

The Third Package defines rules regarding capacity products offered and the harmonization of contracts and related procedures and a draft Network Code on capacity allocation mechanisms has recently been proposed. These measures substantially will increase transparency and compatibility, reduce therefore transaction costs and will facilitate natural gas trade and competition. However, they do not completely address all obstacles discussed above.

Thus, we recommend for future EU involvement:

- The EU should set principles for determining the ideal size of entry-exit zones, but let concerned NRAs and TSOs agree on the result. Boundaries of price zones should reflect the technical and economic conditions rather than political borders; mergers of market areas shall be evaluated on a case-by-case basis based on expected economic benefits and costs. This can best be done by the concerned NRAs in close cooperation with the respective TSOs. Once market areas are merged, there are good economic reasons to implement a system of common tarification. The role for the EU should be limited to support sound agreements between the respective stakeholders; the actual implementation of harmonization of tariff structures and definition of a mechanism to compensate TSOs can be managed at regional level.

- The enforcement of legislation in place (Third Package), and respectively the implementation of recent proposals (draft Network Code CAM), are necessary steps into the right direction to remove barriers to efficient competition.

- We recommend some harmonization in natural gas transmission tarification to ensure that the breakdown of costs among grid users and among entry- and exit points is designed such that as far as possible the principle of cost-reflectiveness is respected. There should be adequate discounts on short-haul transports and an asymmetric reallocation of costs such that 'captive' domestic consumers intentionally have to bear a disproportionately high share of overall costs, shall be prohibited.

- Furthermore, the EU, through ACER, should formulate a set of 'good practice guidelines' regarding natural gas transmission tarification. Entry- and exit charges should be actively used to provide locational signals to grid users wherever this is economically reasonable. Furthermore, similar to the discussions above concerning tariff structures in the electricity sector, commodity-related components should reflect short-run marginal costs in order to avoid distortions in the behavior of shippers in the commodity market and network tariffs should clearly be identified, containing only those cost elements that are related to the transmission activity (i.e. infrastructure investment and operation).

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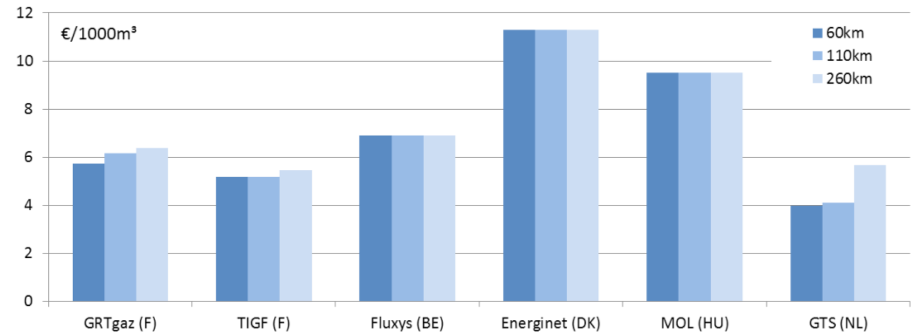
Annex 1: Supplementary information

(a) Transmission network tariffs

Figure 8 shows data on natural gas transmission tariffs for various transported distances. The data have to be regarded with care, since they have been calculated in 2007; thus, levels and also employed methodologies might have changed in the meantime. However, what becomes clear is that there are substantial differences regarding both tariff levels as well as tariff design. ERGEG (2007) reports tariffs, calculated by the respective NRAs, for a selected number of TSOs, which at this time applied an entry-exit system and could make the required data available for ten different grid user standard profiles. The figure below is based on the following assumptions: Standard profile #5 (i.e. transported volume of 500mn m^3/a; maximum capacity of 80,000 $m^3/h/a$; load factor of 0.71); the underlying contract covers firm capacity over one year.

Figure 8: Natural gas transmission tariffs for various transported distances



Source: Own depiction using data from ERGEG (2007)

Table 5 provides some exemplary data on electricity transmission tariffs for the German high voltage grid. These capacity and energy-related components add up to a total charge to be paid for a hypothetical customer (2,500mn kWh/a; maximum capacity use of 500 MW; yearly usage during 5000 h/a) as summarized in the last columns. Again it becomes clear that there are substantial differences regarding both tariff levels as well as tariff design.

Table 5: German electricity transmission tariffs (high voltage grid)

	< 2500h/a		≥ 2500 h/a		Hypothetical grid user	
TSO	€/kW	€ct/kWh	€/kW	€ct/kWh	€	€ct/kWh
50 Hertz	6.31	1.476	35.27	0.318	25,585,000	1.023
Amprion	3.38	0.846	20.85	0.147	14,100,000	0.564
EnBW	2.15	0.784	20.89	0.034	11,295,000	0.452
TenneT	3.01	0.950	25.50	0.050	14,000,000	0.560

Source: Own calculation based on data from company websites

This heterogeneity among tariff levels of different TSOs has also been confirmed by Pérez-Arriaga et al. (2002), conducting a detailed benchmarking study on European transmission tariffs.

(b) Case studies on instruments used to promote investments

Table 6: Instruments used to promote investments

	Examples from natural gas	Examples from electricity
National	• IT: extra return (e.g. regional transmission 2% for 7a; national transmission 2% for 10a) • BE (170km bidirectional pipeline Eynatten-Opwijk): co-funding EEPR	• IT: increments above normal WACC (2% for system security investment; 3% for congestion relieving investment) • UK RIIO model: Incentives based on output delivery
Inter-regional	• Interconnector (B-UK): nTPA & open season; EIB loan of 352mn GBP • Euskadour (ES-F): rTPA & enhanced RoR • BBL (NL-UK): **Exemption** from rTPA	• BritNed (NL-UK): partial **exemption** (exemption from limitation of revenues) • Estlink (FI-Estonia): **Exemption** from rTPA • Interconnector IR-UK: **full exemption** from rTPA and limitation of revenues • AC cable between IT-AT: **Exemption** from rTPA • NorNed (NL-N): TEN-E fund of € 3mn + EIB loan for Dutch TSO of € 140mn; rTPA + congestion revenues • HVDC underground cable F-SP: TEN-E fund of € 225mn + EIB loans
New supply infrastructure	• Various new LNG terminals: 80-90% capacity dedicated to sponsors or **exemptions** from rTPA • Greenstreem (LY-IT): part under LTC • Nabucco: **Exemption** from rTPA	• MedRing: use of RES-regulation to generate returns
[Note: See e.g. Kessel et al. (2011) for an in-depth discussion of experience with exemptions of electricity interconnectors from regulated third party access and/or other provisions related to tarification under Regulation 1228/2003.]		

(c) Charging external effects in other infrastructure sectors

The electricity sector has so far been shielded form including external effects into pricing. However, in particular electricity transmission lines have high negative externalities, and thus the debate to include these appropriately into the pricing is forthcoming. In this context, lessons from other sectors are enlightening, in particular the transportation sector.

For both road and rail transportation, charging external effects is laid out in European Directives. The "Eurovignette" Directive 1999/62/EC "on the charging of heavy goods vehicles" and its amendment 2006/38/EC were very recently being updated by a Commission proposal for a new Directive which has been approved by the European Council on 12 September 2011. It widens the "user pays" principle to also a "polluter pays principle". From now on, Member States have the opportunity to charge for pollution of air and by noise, differentiating with respect to vehicle emission classes (EURO standards). The calculation of costs is standardized and should include air pollution costs, emission factors, monetary pollutant and noise cost per vehicle and person and the population exposed to noise. Also, maximum weighted average external cost charges are stated in the new Directive.

Within certain boundaries, i.e. revenue equivalence and a maximum toll of up 175% of the average toll, it is also possible to charge for congestion.

In rail transportation, EU Directive 2001/14/EC generally prescribes marginal cost pricing but allows for optional mark-ups to consider environmental effects in Article 7(5): "The infrastructure charge may be modified to take account of the cost of the environmental effects caused by the operation of the train. Such a modification shall be differentiated according to the magnitude of the effect caused." However, intermodal competition concerns are raised by the requirement that revenue-increasing environmental charges can only be levied for own usage if other modes of transport charges them to a similar extent. Otherwise, Member States would be assigned to decide on the usage of the revenue-increasing charges. Also, a "time-limited compensation scheme for the use of railway infrastructure for demonstrably unpaid environmental, accident and infrastructure costs of competing modes" are possible under Article 10 in case these costs "exceed the equivalent costs of rail" and it is applied both transparently and free of discrimination to undertakings.

(d) ENTSO-G (2011) – Summary of the Draft Network Code on CAM [gas]

Applies to cross-border interconnection points and interconnections between adjacent entry-exit systems within the same MS; includes principles of co-operation among TSOs regarding the coordination of maintenance, standardization of communication, and capacity calculation.

Allocation of firm capacity:

- **Auctions**; based on a standardized auction design; standardized capacity products (quarterly, monthly, daily, within-day) and taking place simultaneously for all concerned interconnection points
- **Bundled capacity** at interconnection points jointly offered by the respective TSOs (single nomination procedure)
- At least **10%** of the available capacity to be withheld for **short-term** auctions

Interruptible capacity:

- Minimum obligation to offer a daily product for interruptible capacity; at unidirectional interconnection points, backhaul capacity shall be offered at least on interruptible basis; same standard capacity products like for firm capacity
- Standard interruption lead times on which adjacent TSOs decide jointly; default: 2h

Tariffs:

- Since NC on tariff provisions still not in place, a minimum set of rules regarding tariffs is specified: Regulated tariff shall be used as reserve price in all auctions; thereby, the aim should be to achieve *revenue equivalence of booking profiles* (i.e. regardless of the booking behavior of network users, whether they procure longer-term products or a set of products forming a profile, the target revenues should be attained) → Thus a rule is needed on what the relationship between reserve prices of the different capacity products shall be (i.e. determination of multipliers)
- *These multipliers shall be higher than one* to a tariff determined from an annual accounting basis (i.e. reserve price for any

shorter-term product shall aim to compensate for shortfall in sales volume)[37]

- Rules regarding revenue split and reserve price for bundled products[38]
- *Over-recovery*: Auction revenues exceeding the allowed revenue shall be used for different aims, subject to approval by the respective NRA
- *Under-recovery*: TSOs allowed to close the gap by adjusting tariffs [three alternative ways (see ENTSO-G, 2011b; CEER, 2011): (i) additional fee by unit of capacity; (ii) adding a commodity-related tariff component (e.g. UK, which, however, acts like an extra tax on the traded commodity; or (iii) lump sum].

37 See ENTSO-G (2011b) for a first discussion on alternative methodologies to determine such multipliers. Ibid. it is also highlighted that a good match of the target revenues minimizes negative effects of an ex-post management of under- or over-recovery (such as distortions in economic signals, cross-subsidization, distortions in trade due to high commodity tariffs, tariff volatility, etc.).

38 CEER (2011) provides some first insights about possible revenue sharing: e.g. 50/50 split, split proportionately to reserve price, according to investment needs, or according to size of the entry-exit zone.

Annex 2: Potential objectives of tarification and conflicts of interest

Objectives of transmission tariffs

Transmission tariffs include elements paid by the user for the access and the use of a piece of infrastructure. In some cases, transmission tariffs also include other elements such as taxes or the costs of renewable support. Transmission tariffs may therefore serve to recover the costs related to the grid, to provide signals for an efficient use of existing infrastructure and the siting of new generation, network, and load, and to fulfill a distributive function.

It has to be distinguished between different time frames considered: The *short-run perspective* focuses on cost recovery of short-run marginal costs of the existing grid, and incentives for an efficient use of existing capacities. By contrast, the *long-run perspective* focuses on long-term costs including those of new infrastructures. Incentives for the location of supply (electricity generators or gas supply points) and load (demand) can be provided. Contrary to "normal", competitive industries, the cost structure in infrastructure sectors is such that the short-run marginal costs are negligible when compared to the long-run marginal costs, except in cases of congestion when short-run opportunity costs for not being able to use the network may be very high.

Transmission tariffs ideally should respect several regulatory principles (see also Lévêque, 2003a; Pérez-Arriaga and Smeers, 2003; Sakhrani and Parsons, 2010). These include: cost-recovery [tariffs have the role to recover the cost of transmission infrastructure]; *non-discrimination* [the same use of the network must result in the same network tariff under the same circumstances not to distort competition]; and *transparency* [in methodology, pricing, etc.]. National regulators commonly follow these three principles, and the last two are also explicitly required via European law (Regulations 714/2009 and 715/2009). Besides, regulators may orient at other principles, such as economic efficiency, cost causality (or cost reflectiveness), simplicity of the methodology and implementation, and stability of tariffs. Moreover, there are other important aspects that the regulators have to take into account. These firstly include technical aspects; electricity flows follow physical laws, thus, it is technically impossible to determine exactly where a flow is generated and where it ends which implies that electricity transmission tariffs cannot be based on financial transactions. Also the specific characteristics of the national grid play an important role. Regulators should consider the economic impact of tariffs; it makes a difference whether tariffs are charged to consumers or generators. Finally, other policy goals are relevant, too, namely the "new" role of grids as an enabler of the transition towards a carbon-free economy or supply security.

Conflicting objectives and the need to make choices

The multiple objectives mentioned above are not always compatible with each other, and often are in outright conflict. This is not only the case for different tariff structures, e.g. the charges for power and energy, or the distribution between variable and fixed costs; also, a higher allocative precision and time resolution of pricing may conflict with the important qualitative objectives such as transparency, simplicity, and stability of tariffs.

The most basic conflict regards the definition of variable and fixed costs with respect to the short- and longer-run. While short-run marginal cost pricing theoretically produces the first-best result in terms of allocative efficiency, average cost approaches are sometimes favored because they assure a simple allocation of fixed costs (see Olmos and Pérez-Arriaga, 2009, for an in-depth discussion). Here, the interdependence between pure production costs and transaction costs becomes evident: the transaction costs of allocating fixed costs in a marginal-cost pricing system may outweigh the welfare gains of the latter. Moreover, Ramsey tariffs are discriminatory, and cost causality implies that the beneficiary pays; however, positive externalities e.g. from investments in infrastructures supporting decarbonization or supply security might require at least some socialization of costs.

On top of these traditional conflicts, distributional aspects further complicate the choice of "optimal" transmission pricing. Thus, the definition of the basic unit of prices already entails significant distributional effects: fixed cost allocation according to peak power use will disfavor peak users, as compared to using the transported energy as the basis. Any tariff leads to distribution of rents between producers and consumers (e.g. via the explicit definition of G- and L-components); between larger and smaller consumers (depending on the importance of fixed cost allocation); or between consumers in different locations (in cases of locational-specific pricing).

Distributional issues also arise when one compares entire systems of tarification, e.g. short-run locational marginal pricing and zonal pricing. An argument in favor of zonal pricing is the higher competition prevailing in the zone (under the assumption of no internal congestion), leading to a lower danger of market power abuse; on the other hand, if competition and/or regulatory authorities are able to oblige each local producer to supply at marginal costs, consumers stand to benefit from this regime.

It follows that there is not this one optimal tariff design that could be derived based purely on technological characteristics of the system and economic considerations. Rather, transmission tariffs can only be assessed once the objectives of the regulator are well-defined and clear. This requires (explicit or implicit) choices to be made by the regulator, which are not easy to identify in most cases.

Annex 3: Conclusions of Industrial Council Meeting (based on report version "V0", Sept. 2011)

Serge Galant
Technofi
Submission date: September 15, 2011

The question to be answered by the THINK consortium is: "What is the EU involvement needed in electricity and natural gas tarification?"

The tentative answers to the question: As usual, EU involvement may come from many organizations, and regards several options (alone or together): supporting innovation, standardizing, better regulating, harmonizing, enforcing regulations, etc. If there is any involvement, its additionality must be shown.

Clarity: What is still fuzzed in the first draft of the study?

The report must pinpoint:

- What sort of grids could be concerned by EU involvement on tariffs?
- What scope of tariffs to address when EU involvement is at stake?
- What sort of tariff uses must be considered at EU level capable of helping (i) using existing assets more efficiently; (ii) sending signals to favor efficient consumption (with time of use approaches based on consumption pattern); (iii) others…
- What are the drivers, which will require EU intervention (2020 targets, 2050 orientations, Energy Efficiency Directive, others?)
- Based on the above, which EU-based organisations need to be involved? (EC: DG Research, DG Energy, DG Competition, DG Regio), ACER, ENTSO-E, EURELECTRIC?
- What is the additionality of EU involvement? (For instance making politicians understand the future interdependence they will have to pay for in order to ensure security of supply and long-term sustainability)?
- Are there differences in involvement between electricity and gas? If yes, which ones?

Completeness: What are the missing topics to be included?

There is a need for a state of the art on past involvement at EU level on tariffs, the most recent example being the Third Energy Package with the use of tariffs for system innovation funding. This review could bring arguments for pros and cons about further EU involvement.

The second issue is to detail the why of such an involvement, let us mention a few:

- Increased energy interdependence requires a referee to propose compromises where there will be new winners and losers (ex: agricultural policy),
- The need for stable regulations, where a referee is needed to set rules that are fine to the whole EU27,
- The needs for harmonized regulations, which in turn may support technology standards for networks and a reduction in future network investment costs,
- The introduction of a European component in the tariff economic structure, which would help recover investments having a European added

value (say the Super Grid to link with the existing grid, that crosses several control zones and which is needed to convey electric power from the North Sea to Far East Europe,

- The definition of novel incentives to catalyze investments having a European added value (what is the unit of money to be used for future incentives).

The third issue is to address another area of EU involvement: the use of congestion rents by TSOs.

A question was left unanswered: Should ITC issues regarding tariff implementation be covered or left over in the report?

The last issue to be addressed is the role of the target model in defining the possible future involvement of the EU in electricity/gas tariffs.

Coherence: What are the incoherences, which must be treated in the next version?

The draft slides start with two questions: (i) Is there a need to adapt regulation regarding grid tarification? And (ii) Is there a need for stronger EU-involvement? However, there is only one recalled in the conclusions.

Overall, the assembly of attendees converged in saying: No more legislation; just enforce the existing ones. Is this message still coherent with the thinking time line used in this work?

Annex 4: Conclusions of Project Advisors (based on report version "V1", Oct. 2011)

Nils-Henrik von der Fehr

Professor at Department of Economics, University of Oslo

Submission date: October 30, 2011

Introduction

My comments are based on the first draft of the report dated October 14, 2011, as presented at the meeting of the Scientific Council in Brussels on October 18-19, 2011.

The report deals with two very different issues, namely the regulation of TSO revenues (which has to do with incentives for cost efficiency, investment and cost recovery) and tariff setting (which has to do with providing signals for grid usage). The aim is to provide the EU Commission with advice on EU involvement in these tasks. The main conclusion is that there is limited need for direct EU involvement, except perhaps to formulate "good practice guidelines" and harmonize certain tariff elements.

Overall assessment

The report deals with a very broad topic; not only does it involve two very different issues, but each of these are extremely large and complicated. It is therefore inevitable that the report must be somewhat superficial. However, this problem could have been reduced by concentrating attention on a limited set of questions, and, indeed, by avoiding questions that are only tangential, or perhaps not even related, to the topic. Moreover, the conclusions drawn are not always supported by the analysis; while this does not necessarily mean that the conclusions are wrong, they are at least not sufficiently substantiated.

Other comments

Given that the report deals with optimal regulation of revenues and tariffs, one misses a standard by which policy should be measured. This is important not only to specify the goals towards which the policy should aim, but also in order to explain how one could get there.

This is particularly true for the setting of tariffs, which inevitably must be seen as an "optimal tax problem"; the principle of cost-causality can only be followed part of the way, begging the question of how to allocate the remaining fixed costs. In other words, what do we do when cost causality has been exhausted?

The report side steps the issue of tariff level, concentrating instead on tariff structure. While this may be seen as way of narrowing the scope of the analysis, one would like a discussion of why this is permissible. Not only are tariff levels a hot issue, but it is in general difficult to see the structure of tariffs independently of their level; this is particularly true when the point of departure is regulation at the EU level, where ensuring a level playing field across Europe is a concern.

A skepticism towards EU-level regulation shines through the entire text. Such skepticism may well be justified, but it needs to be just that - justified. The report must spell out clearly why EU-level regulation is not required, or indeed counter-productive, rather than just claim, or implicitly assume, that this is the case (where an attempt to provide justification is made, such as in Section 2, the argument tends to be very general and not directed specifically at the issue at hand).

There are also a number of references to fairness (one example occurs on p 27), which need to be clarified. What is the concept of fairness applied and why is it relevant?

A central issue in the debate about transmission in general and transmission tariffs in particular has been the inter-TSO compensation mechanism in the electricity sector (ITC). There are strong doubts about the adequacy of this measure, and the report should spell out in detail its pros and cons.

This is relevant also for the question of adequate investment in transmission facilities, where one may doubt the possibility of reaching agreements based on cost-benefit analysis, even if such could be undertaken appropriately. While one may be skeptical about European-level decisions on (certain types of) transmission investment, such decisions need to be discussed, including the possibility of recovering the costs through a general tariff (say, a flat charge on all users).

Finally, the report is not clear about the allocation of tariff payments between consumers and producers; specifically, the arguments for why the so-called G-factor should be set at a certain level are unclear. This is important, also because the structure of the G-factor may affect the geographical location of new investment in generation and hence efficiency of the overall European electricity industry.

Dörte Fouquet
Lawyer, Partner at Becker Büttner Held
Submission date: October 30, 2011

General comments:

Overall, the report addresses a very interesting and in fact important topic. As such, it could make an important contribution to the current discussion about differences in tarification and tarification structure.

However, in general, the text of the report would need editing. The formulations are sometimes quite unclear and complicated, impeding the comprehensiveness of the text. Long sentences should be split up into separate "bite sized" ones to improve readability. Typos and spelling mistakes would need to be corrected.

Conceptual comments:

First, one should think about who the actors in the gas supply market of the future would be and take this future energy supply landscape as a basis. While the role for TSOs is obvious, in particular when considering the current infrastructure and the cross-border aspect in the gas trade, one should reconsider the role for DSOs. With increased decentralized electricity generation and the according use of local infrastructure, the gas supply will not remain unaffected. As examples of such impacts new technologies to store electricity in existing gas infrastructure, Smart Grids and Smart Heating systems or the trend to have natural gas more and more as back up capacity could be mentioned. The energy supply of the future will thus require more and more cooperation between DSOs and TSOs. The report in this respect could pay more attention in particular to DSOs and their concerns, as well as Energy Service Companies and other market players.

Second, and certainly related, the question of "locational signals" and how far they should go needs some more thinking. Should they lead to "one European Energy Infrastructure/Grid", commonly owned by all Member States, possibly even managed by a European Agency? The report is unclear on some points also what concerns merging markets – for example it says that "Boundaries of price zones should reflect the technical and economic conditions rather than political borders" which suggests a reorganization of the natural gas price zones; or "once market areas are combined" which even takes merger as a precondition? However, they should not, I would say. Not only would Member States oppose to any such idea, which would be in conflict with their national laws and principles (e.g. the concept of "Daseinsvorsorge" enshrined in the German Grundgesetz, art. 28GG) as well as with EU law (in particular the principle of subsidiarity), but it would likely lead to overly complicated, administratively chaotic situations. Thus locational signals should be kept on a Member State, regional or even local level which again needs participation and input also from consumers, DSOs, and other stakeholders in the area.

Comments on the content:

The formulation that "idea of European superhighways is driven by different motivations, e.g. the wish to transport solar energy from North Africa to Central Europe, or to transport nuclear energy from Eastern to Western Europe, or to transport more natural gas from the Caspian Sea to Central Europe" is problematic as those motivations are certainly not shared among the all the Member States and not a Commission motivation. Distinctions should be made and it should be indicated who follows which interests.

Both the explanations on the principle of subsidiarity and the description of externalities could be clearer and more detailed.

The alleged distortions of competition are not entirely convincing either; maybe paragraph sketching the situation as it currently stands may give more strength to the following arguments.

While it is true that legal (and regulatory) certainty is important for investors (p. 12), that does not necessarily mean that regulatory periods need to be extended – a legal or political commitment to follow a certain policy can do the same. To the contrary, extending regulatory periods may also have disadvantages such as potential abuse, strengthening of market positions. Those disadvantages should be mentioned as well.

The picture on "sharing of network operator charges" and "socialization" of grid costs and transmission costs is somehow flawed as it does not mention any other reasons than "former absence of competition". The allocation rules may well be part of the overall legislative and regulatory system.

On the recommendations that tariffs for the cost of infrastructure should not be charged by energy transported but instead based on booked capacity, this is what is proposed e.g. in Belgium now. However, the system already faces criticism and opposition in particular from the renewable energy sector, as they find it discriminatory; they would have to pay even if they would not use the grid. One should take this discussion into account, to present both sides, and could possibly differentiate.

Annex 5: Conclusions of Public Consultation (based on report version "V2", Nov. 2011)

Overall recommendations

Setting the TSO revenues and setting tariffs are separate activities. Heterogeneity in approach for the former should not be an issue as long as the TSO is provided with sufficient revenues (subject to appropriate risk coverage) under price controls, in order to deliver necessary non-load and load related investment. TSO tariffs are then allowed to recover that revenue. This should be left under the auspices of Member States, as of now. The right tariff design should reflect national circumstances,

There are however obvious reasons for increased EU involvement:

1. A common set of principles should be applied across Member States to facilitate regional harmonization: this is an area where the EU could more obviously increase its role where it may detect that there are inconsistencies in Member State approaches which impede European harmonization and competition objectives.
2. revenue recovery and tariffs issues relating to investments driven by cross border issues should be addressed at EU level, including (i) cross border circuits, interconnectors etc… and (ii) within border investment driven by transit issues. There is a frequent disconnect between the bearer of investment costs and the beneficiary of those investments. An overarching party should address such issues which involve two or member states with a potential for inequity in sharing of costs and benefits.

Simplicity should prevail when dealing with revenues and tariffs.

1. Pragmatism should be the rule: European bodies provide robust guidelines for national application but address any other wider European objective separately from an involvement in tariff design.
2. Policy objectives which are not consistent with economics should be applied outside of tariffs and/or implemented in a separate simple and transparent manner which is not stirred into tariff design.
3. Substantial new generation investment will come from a large number of new investors in the industry: tariffs need to be sufficiently transparent and predictable (which does not mean stable) to enable them to invest with confidence in their knowledge of network costs.

The complexity of the issues raised in the report requires some caution in the recommendations:

1. It is recommended that tariffs for the cost of infrastructure should not be charged by energy transported, but instead based on booked capacity depending on the grid user type or lump-sum. A careful analysis is needed to analyze the differences between the two-part tariff (energy and demand components) and the tariff for time of use (TOU), in order to highlight pros and cons of both types of tariffs.
2. The main differences between Member States for the calculation of allowed revenues, e.g. calculation of the regulated assets base (RAB), calculation of CAPEX (including depreciation rates), OPEX and the WACC and etc., should be further highlighted before proposing harmonization perspectives.
3. The prerequisites for a detailed cost-benefit analysis of a complete harmonization of tariff

design need to be stated.

4. A comprehensive comparison of regulatory frameworks is needed beyond the ERGEG 2007 study, which revealed significant differences in natural gas tariff levels: these differences were mainly caused by exogenous factors. Criteria for an appropriate comparison in view of regulation purposes would probably raise motivations to increase the transmission companies' effective performance.
5. The majority of natural gas data used in this study come from the Kema/Rekk report (2009): these data might not reflect any longer the current situation of the natural gas market in EU 27.

Regulation issues for TSO revenues

Electricity sector

Consensus on how to account for innovation investments is still to be found.

Gas sector

A great heterogeneity in allowed revenues determination might imply unjustified differences between countries which in turn could impede the development of new infrastructures, either because of an inadequate remuneration framework leading to a lack of investment on one side, or because of excess remuneration on one side which makes the infrastructure too expensive to pass an eventual economic test.

Harmonizing the allowed revenues calculation across the whole of Europe is a challenging task. The costs of harmonization in methodologies used to calculate allowed revenues might substantially exceed its benefits. Yet, possible adverse effects of the current heterogeneity should not be underestimated: some measures should be put in place to better balance harmonization benefits and costs.

Transmission grid tariff issues in the electricity sector

The determination of capacity requirements is changing and becoming more complex, because of the increasing penetration of intermittent renewables: this may have consequences for tariff design. But it will remain a capacity issue and not an energy issue. Future network investments will be driven by the needs to accommodate low load factor plants and/or volatile power flows with relatively short/infrequent periods of high capacity needs.

The argument to introduce a minimum G component might be the wrong option. Whether a generator is making a profit or breaking even, it must, by definition pass through the cost (otherwise it would be making a loss): this will remain true regardless of market design. Thus, there is no need to set a minimum threshold or indeed a maximum threshold although most experts would agree the most effective solution for generator tariffs is net G=0 with locational capacity based tariffs. Besides, is there evidence from countries that do have introduced a G-component that the location decision of generation was indeed modified? Many generators, especially renewables, are no longer free with regard to their location decision.

On the contrary, the amount of capacity or electrical energy which is generated by generation equipment owned by the customer should be charged and included in the calculation of transmission tariff. Otherwise, since large customers or self-generators start to have their own generation units (small power plants), the rest cost of the network would be charged to the smaller customers: this may result in higher prices for the most vulnerable customers, especially when the G component is not applied.

Overall, it would be useful to set the respective harmonizing provisions in the common EU document.

A European tariff component might be an interesting option to collect money from grid users that than could be re-invested into infrastructure projects of European value that suffer from strong externalities. The use of such an instrument has several advantages when compared to so-called traditional public funding: cross-subsidization is reduced since grid users instead of general tax payers are charged; demand elasticity for electricity and gas is considered to be relatively low.

Yet, infrastructure projects will rarely truly benefit every region or country in Europe – consequently, a European Tariff component implies cross-subsidizations between different regions and may thus also lack acceptance by citizens. Different levels of purchasing power in different countries will make the determination of a "fair" amount problematic. In addition, if substantial amounts are collected and redistributed via a European tariff component, players might focus on rent-seeking rather than trying to internalize the external effects through an adequate cost allocation.

Transmission grid tariff issues in the natural gas sector

A comprehensive comparison of regulatory frameworks is needed beyond the ERGEG 2007 study which has revealed significant differences in natural gas tariff levels and these differences mainly were caused by exogenous factors. Criteria for an appropriate comparison in view of regulation purposes would probably raise motivations to increase the transmission companies' effective performance.

Increasing efficient competition in the gas sector while avoiding cross-subsidies requires paying a special attention with the methodology to calculate entry-exit tariffs, and its implications on cost allocations: There is a risk that some system tariff decisions might be adopted to recover, more or less of the costs from interconnection points, when compared to what would happen in a cost-reflective methodology. Revenues from auctions of Bundled Capacity will probably be split between the TSOs placing capacity elements in the bundle according to a pro-rata rule: there is a risk of inflating reserve prices.

This is another reason to reinforce the harmonization of tariff methodologies across the EU.

European energy regulators' comments on FSR THINK! Consultation on EU involvement in electricity and natural gas transmission grid tarification

1 December 2011

Introduction

European energy regulators welcome the opportunity to respond to the latest draft report in the THINK! series, addressing the possibilities for EU involvement in electricity and natural gas transmission grid tarification.

In general terms, we concur with the conclusion that heterogeneity in regulation of TSOs revenues does not hamper adequate investments or impede efficient competition in either the gas or electricity sectors. We also agree with the conclusion that, given this, the need for intervention at an EU wide level on this topic is limited – but we see that there could be a role for sharing best practice in regulation and reporting. On the conclusions surrounding the approach to electricity and gas tarification and the need to EU involvement at this level, we have more detailed comments to make.

Across both gas and electricity we would urge further work in the report to reflect the current status of discussions within the Regulatory sphere, for example: acknowledgement of the strong links with the target models for cross border trade (capacity allocation and congestion management) in both gas and electricity.

We call for more discussion of the analysis that supports some of the final conclusions in the report, and urge the inclusion of evidence from Member States where these approaches are already in place or a more detailed reflection of the breadth of alternative options. This applies particularly to the benefits of the locational G-component in electricity tarification, and to the discussion of reserve prices in gas tarification.

We also highlight the cross cutting and interacting role of the draft Energy Infrastructure Package Legislation. In its current form, the legislation proposes regulatory intervention, potentially in the form of incentives for System Operators, as well as Public Funding for co-financing of some projects and cross-border cost allocation of the relevant investments taking into account social, economic and environmental costs and benefits. Further analysis to draw out interactions between this new piece of legislation and the topic of the THINK! paper would be helpful.

In the remainder of these comments we address electricity and gas tarification issues in turn, before making some concluding remarks.

Electricity Tarification:

The THINK! report concludes that the current heterogeneity in electricity transmission tariffs probably does impede both future infrastructure investments and efficiency, and given this also concludes that EU wide intervention pushing for harmonisation of some aspects of electricity tarification could have some positive impact.

Specifically the report recommends: (i) harmonisation of tariffs along with inclusion of a generator (G) charge and a locational element, (ii) definition of costs to be included in tariff charges and limitation of kWh tariff components and (iii) redesign of ITC mechanism to create ex-ante charge and support new investment. With respect to these conclusions Regulators have several specific comments and we would also urge the authors to provide more detail on the extent to which tariff harmonisation is achievable independently from harmonisation of any other feature of the revenue regulation:

G-component, locational signals and demand tariffs
We welcome the discussion of the G-component and locational element to transmission charges and recognise that a G-component charge, and a location element to the transmission tariffs could result in more efficient signals to grid users. From a theoretical stance, this encourages generation to site in less costly parts of the network, and sends signals that could incentivise demand participation relevant to longer term network development issues.

However, we feel that more analysis and evidence is needed to support this conclusion fully, and to extrapolate the benefits to a real-world application. In particular, we would like to see further analysis of the distributional effects of a G-component charge in terms of costs, to ascertain how this actually affects profits and behaviours. For example, we advocate exploration through examples of what element of this cost is passed through in wholesale price, how does this influence generator profitability, what is the most suitable variable for the charge and what impact does it have on economic efficiency? Also, consideration of how any G-component may interact with future capacity mechanisms that could be developed in some countries would be helpful.

We also feel that more evidence is needed to support the conclusion that the G-component actually incentivises efficient generator investment behaviours in practice. There are some positive examples of the impact of locational G-charges. On the other hand, in many cases the choice for generator location can be limited, particularly in the case of renewable generation. Further evidence of experiences from countries with a locational G-component and analysis of the specific impact on renewable generation of this proposal are needed to support this conclusion. In this context, we would also like to see further analysis of the impact of any proposed G-component on government support mechanisms for renewable generation, and further impact on investment decisions. The CEER consultation currently underway, exploring the implications of non-harmonised renewable support schemes may also provide additional evidence to address this area.

A wider perspective is also needed; for harmonisation of tariffs to be effective, a consideration of connection charges is also needed. Although many regimes have now moved away from deep connection charges, considerable heterogeneity still remains in this component of the tariff charging approach. To consider harmonisation without inclusion of the element of the (sometimes fixed) charge linked to grid connection misses an opportunity to arrive at the most efficient solution.

Finally, we highlight the point that grid users may respond to a €/MWh component in charges through lower energy loads. Because individual peak demands are not synchronous, lower energy loads cause a lower peak demand on the grid. In others words, although electricity transmission is largely a fixed cost industry (with respect to volumes transmitted for a given capacity), the inclusion of an energy component (€/MWh) in the tariffs may then be cost reflective and efficient. So whilst a G-component could be a helpful element in incentivising efficient behaviours in generation, demand also plays a role in the dimensioning of the transmission network. Efficient price signals should not ignore the role that responsive demand can play, and the potential for consideration of non-network solutions (e.g. demand side management) as an alternative to network investments.

Compatibility of G-component, ITC charge and the target model for cross border trade
The report does not draw out the potential links between the various transmission tarification approaches or compensation mechanisms that are present in the system today, or the need to ensure consistency and coherency between mechanisms and the long and short term timeframes.

For example, the ITC compensates for transit volumes on infrastructure and losses and is a charge calculated ex-post and then allocated between TSOs (a socialised charge from the grid users perspective). A locational G-component is an ex-ante targeted charge (usually per MW, sometimes including a grid connection charge) to individual generators with the purpose of providing guidance for efficient connection points. Finally, congestion rent is an ex-post, partially socialised “charge” (linked with market coupling that requires efficient short term prices reflecting a locational element) which reflects the scarcity of (cross-zonal) transmission capacity.

In general terms, any approach to tarification should aim to target costs (user pays or beneficiary pays where different), which implies attempting to minimise socialisation, and should avoid unproductive overlap of different charging methods according to the different purposes they serve. For example, at present the ITC is a relatively small part of national TSO revenues. In this case the loss of efficiency in socialisation of this charge is outweighed by the benefits from increased competition. But, as the level of market and physical integration grows this level of socialisation have more drawbacks than benefits and a more targeted scheme for the compensation for use of infrastructure might become appropriate.

The long term and short term charges that exist in transmission tarification are not independent, all are reflecting the cost of access to or usage of the same infrastructure in different, and possibly overlapping ways. Acknowledgement of these potential interfaces or interactions in the THINK! report would be helpful. Synchronisation between timeframes is also important. The target model for capacity allocation and congestion management is predicated on short term locational signals captured within wholesale market prices. Coherency of this approach with long term transmission tarification is essential, and not currently a feature of the THINK! analysis.

ITC redesign
At present, ITC is an ex-post charge that was designed to facilitate remuneration of national TSOs for hosting cross border flows. In its present form, it is not designed to address the cost allocation challenges faced in building new infrastructure where cost and benefits accrue to different parties. Addressing this issue by adapting the ITC mechanism would be a challenge that requires substantial amendments to the current ITC design. If an ITC redesign cannot be achieved in the short run, the cost allocation challenges for new infrastructure projects may possibly be better addressed on a bilateral and case-by-case basis or, where appropriate, on a regional basis for example in Regional Initiatives such as the North Seas Countries Offshore Grid Initiative (NSCOGI) and the Baltic Energy Market Integration Project (BEMIP) .

Regarding the conclusion that the ITC mechanism should be redesigned to create an ex-ante charge that could act as a stimulus for new cross border interconnector investment, views among regulators are mixed regarding the value of this proposal. We would therefore encourage exploration of the wider options available to secure delivery of cross border infrastructure, particularly in light of the latest development of the Energy Infrastructure Package and the mechanisms alluded to in this Package; and we ask the authors to consider practicality of these options, as well as the trade-offs against priorities in the real world.

<u>Gas Tarification:</u>

We welcome the way the analysis has been developed and, in particular, the discussion on the trade-offs between short and long term issues of investment and efficient competition. However, we have similar concerns as expressed in the electricity tarification section above, that sometimes the conclusions lack sufficient justification.

The report concludes that heterogeneity in natural gas transmission tarification does not hamper adequate investments but may hamper efficient competition and asserts that complete harmonisation of tariff structures across the EU is not justified on economic grounds. We generally agree with the point that harmonisation should be promoted carefully and, in particular, that benefits should outweigh the drawbacks of any change. But, we would like to see stronger evidence and arguments to support these conclusions, in particular further detailed work to explore the benefits and drawbacks of harmonised tariff design structures.

Short-term capacity

As explained in the report, short term capacity pricing is an important aspect of current debates on tariffs. The developments in box 3, at the end of section 5, highlight important issues related to off-peak periods and revenue aspects. To present the full picture, however, more emphasis should be put on the arguments for and against the application of low/high short-term reserve prices, in particular regarding barriers to cross-border trade and include factual evidence from Member States where these approaches are already in place.

The study presents "ensuring signals for long-term investments" as a key benefit of using multipliers greater than 1; it should also mention potential issues such as risks of distorted price signals when prices do not equal marginal cost. The text should be more careful when presenting the downsides of low short-term capacity reserve prices and especially when it focuses on the lessons from the GB experience; the report may benefit from a fuller description of the experiences there. Preference for the short term indeed has some drawbacks but, at the same time, the GB auction regime has allowed for regular incremental capacity developments. Regulators are not yet in a position to express a clear preference for a specific level of short term reserve prices, but we would welcome further development of the report to set out the pros and cons of the different options in a balanced way.

Tariff setting

In the discussions on tariff setting, very little is said about reserve prices even though auctions have been adopted as standard allocation mechanism for interconnection capacity. In addition, the uncertainty inherent in auction results will translate into over- or under-recoveries; mechanisms aimed at compensating the gap between actual and allowed revenues is an important aspect of tariffs which the study does not really mention, except when talking about the commodity charge in 5.4. The issue of how to split a TSO's allowed revenue between domestic and cross-border flows is not addressed either. Implicit allocation of capacity in the gas sector could also be mentioned since it has been an important aspect in the discussions on the gas target model.

Objectives

We note that the objectives of tariffs presented in the introduction, on page 31 and in Annex 3 omit key objectives, for example in comparison to Regulation (EC) 715/2009. We suggest adding the objective of "facilitating efficient gas trade and competition" on the same level as the principles noted, along with economic efficiency.

Conclusions:

European energy regulators are committed to continuing to work on the topic of tarification. Discussions on gas tarification have been ongoing throughout 2011. At the 20th Madrid Forum in September 2011, ACER was invited to consult stakeholders on the scope of the Framework Guidelines on Gas Harmonised Transmission Tariff Structures. It was also requested to present the outcome of the consultation, as well as a first outline of the Framework Guideline at an early meeting of the Forum. ACER intends to launch a public consultation shortly to ask stakeholders about their views on the scope and the main policy options of the tariff work such as, for instance, reserve price structure and cost recovery.

In electricity, historically work on this area has focused on development of the ITC scheme and associated Guidelines. We look forward to building on this experience, and engaging with the Commission over the next 12 months to understand whether further interventions are needed to encourage optimal levels of cross border investments and promote efficiency and competition.

Tariff Working Area
Response to THINK
29 November 2011

TAR049-11_Final

ENTSOG response to THINK public consultation

THINK Topic 6 – DRAFT Version V2: "EU involvement in electricity and natural gas transmission grid tarification"

ENTSOG would like to thank THINK for the opportunity to comment on its draft report entitled: "EU involvement in electricity and natural gas transmission grid tarification". The draft report is balanced and identifies many of the issues previously pinpointed by gas TSOs. We are particularly pleased that the economic trade-offs involved in some of the policy decisions are clearly stated.

ENTSOG would like to reiterate the following positions that it has put forward on other occasions.

1. Investment climate

For new investments to come on stream, even if there is adequate user commitment, the risk-reward ratio for the investor must be set correctly within the regulatory regime. The rate of return must be commensurate with the cost of capital. The draft THINK report gives examples on how some regulators are aiming to achieve this, e.g. by allowing a premium on new investments, which could serve as models for other national regulators. ACER might firstly play a role in identifying where national regulatory agencies put too much emphasis on slashing transportation/asset costs at the expense of wider internal energy market interests, and secondly in fostering successful practices for incentivising new infrastructure.

Preference should be given to the underwriting of investments by market demand, in the form of long term commitments by system users who book long term capacity. However, the draft report also states that "Adequate investments may also include projects that are socially desirable but not profitable from the isolated investor's point of view." From gas TSO's perspective, these are for instance investments in security of supply which are not sufficiently underwritten (adequately booked long-term) by the system users to warrant infrastructure investment. We would like to question whether some EU rules and involvement may not be warranted, if national regulatory regimes do not foresee coverage of the gap in the underwriting of investments (i.e. cost allocation to system users with direct benefits from the capacities or services provided).

2. Merging of market areas

ENTSOG fully agrees that market area mergers involve significant trade-offs, which are well-reflected in the draft THINK report, and therefore calls for a careful case-by-case analysis of the costs and benefits before any mergers. Tariff issues are secondary to the technical/physical issues associated with the offer of de-coupled entry-exit capacities (The Nordic power sector provides a recent example where in Sweden in 2011 a larger market area was broken up into multiple zones, reflecting the underlying physical infrastructure). Nevertheless, the tariff issues also need to be examined, particularly from a cross-border perspective. On an EU level, there may need to be some assistance in resolving some of these issues.

3. Capacity products

"Chain-link-products" are a capacity allocation issue, not primarily a tariff issue. In the CAM network code, ENTSOG does not foresee a linking of auctions, because it is discriminatory in nature (capacities would be tailored to those who can use a certain route and exclude other system users competing for the same capacity). They also counter the hub-to-hub logic of the Third Package, and risk fragmenting the capacity market. Additionally a secondary market in capacity enabled by the TSOs and other CMP arrangements may free up capacity for subsequent reallocation to the system users having the highest willingness to pay. Thus, those not securing their desired capacity allocations in the initial long term capacity auctions will have several options available to secure their capacity requirements. Furthermore, ENTSOG anticipates that additional attention will be given to determine the rules and processes that might be associated with the provision of incremental capacities beyond those currently supported by the existing gas transmission network infrastructure. These processes need to build upon lessons learned from the experience of open season and other market test based approaches. Finally, in the longer run, when markets are matured, enhanced market linkage mechanisms may develop, as presented in ENTSOG's response to the CEER Target Model consultation.

4. Pancaking

"Pancaking" (i.e. the claim that transports across several entry-exit zones add up to higher charges than they create costs) has to be looked at carefully: In entry-exit systems, there may actually often be an inherent, systematic problem that leads to disproportional advantages for long-haul transports within the entry-exit system. Where the above disproportionality occurs, shorter transports have a higher tariff weight relative to the distance transported and longer transports have a disproportionally lower weight. Consequently, there may be something that one could call "reverse pancaking", which means that a transport across merged zones would be less cost-reflective than a transport over several separated zones is. The European gas system both delivers long-distance transports, as well as shorter distance transports. Given that with the size of a market area, the inherent cross subsidies become bigger, and that the gas transport system in different countries serves different purposes, such cross-subsidies should be included in the considerations of costs and benefits of mergers.

5. Short- and long term capacity pricing

ENTSOG particularly supports the draft report's findings with regard to the pricing of long term versus short term capacity products. We agree with the conclusion that discounts on short term capacity will lead to significant market distortions and may jeopardise the aim of "2014", as well as undermine the European gas system's role of delivering long-distance transports. A pricing arrangement that does not allow for proper cost recovery through capacity charges, due to a flight of users to "cheap" short term capacity, will be distortive by introducing cross-subsidies. Furthermore, with a flight from longer term booking, timely signals for efficient investments are lost.

Therefore, ENTSOG has put forward its revenue equivalence principle. This pricing scheme is aimed at creating an aggregate equivalence of flat bookings versus profiled bookings for short term products. It is inherently incentive neutral and consequently allows system users to procure capacity when they identify a need for it. It shall minimise any undue incentives either to hoard capacity, or to massively substitute longer term for short term products. ENTSOG will codify this principle in the CAM network code, which should then become binding on an EU level.

ENTSO-E response to the public consultation

ENTSO-E welcomes the opportunity to comment on the THINK-report relating to EU involvement in electricity and natural gas transmission grid tariffs issued on the 1st November. The comments in this report have been provided from a TSO expert perspective and should not be viewed as a formal ENTSO-E position.

The report covers a series of important issues which have a bearing on the efficient functioning of the internal electricity market. As the report rightly notes, the method for setting tariffs and regulatory regimes which European TSOs face currently differ significantly between Member States. As electricity markets become increasingly harmonized, via the implementation of the European target model for electricity market design, through the impacts of network codes and as a consequence of constructing new infrastructure, the need to amend the methods of setting transmission tariffs in order to avoid distortions in the functioning of that market may also increase.

ENTSO-E notes that previous legislation has introduced a series of principles which we support and consider should continue to form the basis of tariff setting. That is, tariffs should be non-discriminatory, cost-reflective, should facilitate competition and should promote the efficient development of networks and functioning of markets.

ENTSO-E welcomes the report as a valuable input to an ongoing process to develop and consult on proposals for the progressive harmonization of elements of transmission tariffs. ENTSO-E looks forward to playing an active part in this process and we would be pleased to contribute where we can usefully do so. Our response briefly summarizes each of the study's findings before providing ENTSO-E's view. We would be pleased to discuss these positions in more detail.

1. Investment Incentives

Regarding Investment Incentives the study concludes that the current heterogeneity in domestic regulatory frameworks does not influence the investment activity of TSOs. Rather, the overall level of inadequate regulatory returns throughout Europe seems to negatively impact TSO investments. This leads the authors to conclude that no EU involvement beyond the provision of co-financing funds and the identification of regulatory best practices is required. According to the report the current provisions of the EU Regulation 714/2009 on congestion revenue usage provide further investment incentives to TSOs.

ENTSO-E would like to stress the importance of appropriate investment incentives and of rewards which are proportionate to the risks of projects. We would also like to highlight that both our members and, increasingly, members of the finance community consider that this is not the case in many parts of Europe today. Therefore discussions about mechanisms to create incentives are welcome.

ENTSO-E supports the idea that the identification of regulatory best practices would represent a means of increasing transparency and could, potentially, contribute to the creation of investment incentives. While we agree that regulators should continue to have a central role in defining incentives in the majority of cases, contrary to the findings of the study, we consider that specific, independent mechanisms could be introduced at EU level in specific cases where there are particular barriers or risks to investment which need to be overcome or where national regulatory intervention has proved ineffective . Intervention could be direct or involve working with ACER or NRAs to develop appropriate solutions to European issues. We also consider that focused intervention by the EU could also prove useful in sending signals to potential investors and supporting the prioritization of investments of EU interest. Further details on ENTSO-E's views and concepts can be found in a recent ENTSO-E paper on this topic available from the ENTSO-E website.

With regard to the existing provisions on the usage of congestion revenues (Article 16 para. 6 of the EU Regulation 714/2009), we are not convinced that significant cross-border investment incentives are created by using congestion revenues to invest and are aware of cases in which no incentive or a disincentive to invest is provided. In ENTSO-E´s view additional incentives are required to deliver much needed cross-border investments in a timely manner.

2. Tariff Harmonization

The study concludes that current heterogeneity in tariffs hampers adequate investments and impede efficient competition. It recommends a harmonization of national tariffs such that:

- Generators in all EU countries pay for part of the network costs and that locational signals to grid users are provided.
- Energy based tariffs (€/MWh) be avoided.
- Tariff structures and not absolute levels are harmonized. The main reason for this conclusion is that absolute tariff levels depend on the individual network costs which in turn depend on the heterogeneous network structures in different Member States.

ENTSO-E considers that the issues raised by the THINK report regarding transmission tariffs are important and welcomes the balanced analysis set out in the report.

Europe is facing a significant need for investment in both generation and transmission capacity. It is important that the overall cost of this investment is minimized and that efficient decisions are encouraged and made. In this context we feel that the study overestimates the role of grid tariffs while, as said before, it underestimates the role of regulatory incentives. TSO tariffs represent a relatively small element among all the economic signals that affect investment decisions in generation. Harmonization of that element across Europe is likely to have a limited effect overall, particularly on transmission investment.

This is not to say, however, that tariff harmonization as such shouldn't be pursued. From a theoretical viewpoint ENTSO-E considers that EU wide locational signals for generators could be beneficial. Such an approach would incentivize investors to consider the impact of an investment on the overall transmission grid. Hence, if appropriately set, an optimal trade-off between all costs – including grid reinforcements - could be achieved. Despite this obvious advantage the efforts necessary to design and implement a harmonized G- component should not be underestimated. The report rightly states that no “best method” has been identified yet. Defining and agreeing upon such a scheme would not be a straightforward task and would require significant time and consultation.

ENTSO-E fully supports the conclusion that tariff setting principles and structures rather than absolute tariff levels should be harmonized. The underlying reason – namely the heterogeneous network structures and regulatory modes - gains our full support. ENTSO-E also considers that both capacity/power oriented tariffs and energy based tariffs have a role to play in promoting efficient system development and system operation. As such, we support the view that an appropriate balance needs to be found.

ENTSO-E also supports the suggestion to increase the transparency of grid tariffs and tariff calculation methodologies. Indeed we have taken steps to promote this process via our annual tariff report. In particular, we note that costs related to the support and integration of renewables are often included in these tariffs, although these costs are not always grid related (e.g. feed-in tariffs). A more transparent representation of how these costs translate into grid tariffs would help to explain the general trend of increasing grid tariffs.

3. Cost allocation

According to the study the lack of provisions on the sharing of costs for new infrastructure projects hampers the investment activities of TSOs. Therefore, the study suggests that the current ITC mechanism be redesigned to properly allocate these expenses. It goes on to say that an independent European expert team should investigate the issue.

ENTSO-E would like to stress that cost allocation is not the most contentious issue associated with new infrastructure investments. While cost allocation questions can certainly be complex, we are not aware of cases in which they have prevented cross-border or other joint projects from being delivered. Bilateral negotiations between TSOs and approvals by flexible regulators appear capable of solving this issue. Compared to cost allocation principles investment incentives have by far a more significant impact on TSOs' investment decisions.

We also note proposals to amend the Inter TSO compensation mechanism. The present ITC scheme has been designed to compensate for hosting cross border flows (transits) arising from electricity exports and imports. The purpose of ITC is not to provide a basis for cost and benefit allocation of new investments. Rather, it is a consensual framework between 41 TSOs across Europe on compensating the mutual use of their grids by physical transits. This arrangement was developed and implemented by ENTSO-E and is now underwritten by legislation.

The suggested approach of involving an independent expert team in transmission planning – a pure TSO task - seems inappropriate.

THINK

THINK is a project funded by the 7th Framework Programme. It provides knowledge support to policy making by the European Commission in the context of the Strategic Energy Technology Plan. The project is organized around a multidisciplinary group of 23 experts from 14 countries covering five dimensions of energy policy: science and technology, market and network economics, regulation, law, and policy implementation. Each semester, the permanent research team based in Florence works on two reports, going through the quality process of the THINK Tank. This includes an Expert Hearing to test the robustness of the work, a discussion meeting with the Scientific Council of the THINK Tank, and a Public Consultation to test the public acceptance of different policy options by involving the broader community.

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